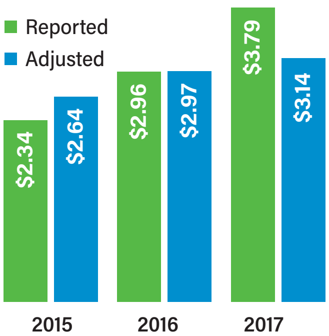
WEC Energy Group

FOCUSED ON **PERFORMANCE**

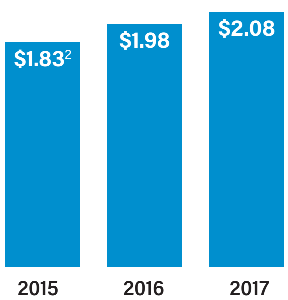
A TRACK RECORD OF **RESULTS**

2017 Annual Report

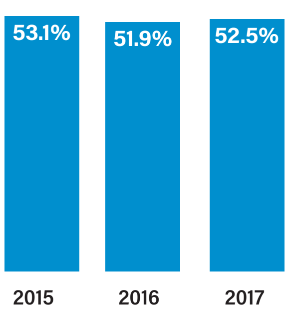
Earnings per share[1]



Dividends per share



Year-end debt to total capital[3]



1. Adjusted earnings per share exclude costs related to the acquisition of Integrys totaling 30 cents per share and 1 cent per share in 2015 and 2016, respectively. Adjusted 2017 earnings per share exclude a one-time, non-cash gain of 65 cents per share related to the new tax law.
2. Annualized based on 4th quarter 2015 dividend of $0.4575.
3. Attributes $250 million of 2007 Series A Junior Subordinated Notes to common equity. A majority of the rating agencies currently attribute at least 50% common equity to these securities. For further details, see Capital Resources under Liquidity and Capital Resources in the 2017 annual financial statements.

Financial Snapshot

(In millions, except per share data and percentages)

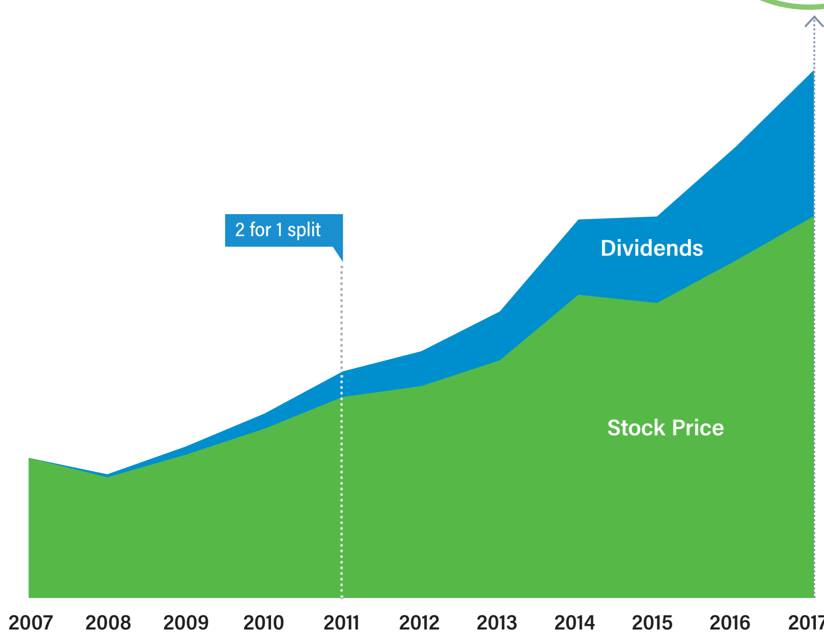
	2017	2016	Change
GAAP Earnings	$1,203.7	$939.0	28%
GAAP Earnings per share	$3.79	$2.96	28%
Adjusted earnings*	$997.0	$941.1	6%
Adjusted earnings per share*	$3.14	$2.97	6%
Dividends per share	$2.08	$1.98	5.1%
Dividend yield	3.1%	3.4%	
Diluted average shares outstanding	317.2	316.9	
GAAP return on average common equity	13.09%	10.68%	
Adjusted return on average common equity*	10.84%	10.70%	
Book value per share	$29.98	$28.29	6%
Total assets	$31,591	$30,123	5%
Market price per share at year-end	$66.43	$58.65	13%
Market capitalization at year-end	$20,964	$18,511	13%

* Excludes $206.7 million ($0.65 per share) of tax benefits related to the new tax law in 2017, and $3.5 million of pre-tax acquisition costs and a related $1.4 million ($0.01 per share) tax impact in 2016.

Total Shareholder Return

WEC Energy Group consistently delivers among the best total returns in the industry. The illustration demonstrates our stock price appreciation plus the compound effect of dividend growth over the past decade.

A $100 investment has grown to a total value of $377



To our stockholders,

I'm pleased to report that our company delivered another year of progress in 2017. On virtually every meaningful measure – from network reliability to customer satisfaction to community involvement – we continued to perform at a high level.

We achieved record financial results. Our largest utility, We Energies, was named the most reliable utility in America and the best in the Midwest for the seventh year running. We made significant progress upgrading the natural gas infrastructure in Chicago. And after reviewing our environmental, social and governance practices, Corporate Responsibility Magazine named us one of the best corporate citizens in the nation.

In addition, our track record of reliability and competitive pricing was a factor in the decision by Foxconn Technology Group to invest $10 billion in a massive, high-tech manufacturing campus in Wisconsin. This is one of the largest economic development projects in American history. We expect Foxconn to employee 13,000 people as they create a brand new industry here in the United States.

Now, for a few details. Our adjusted earnings for 2017 totaled $3.14 a share – the highest earnings per share in company history. These reported earnings ***exclude*** a one-time, non-cash gain of 65 cents a share from the tax reform law that was signed last December. This one-time, non-cash gain reflects the application of the new tax law to the company's non-utility assets and to the assets of the parent company.

Over time, the impact of tax reform will also benefit our utilities. And we are filing plans with regulators in each of the four states we serve to channel the impact of a lower tax rate into direct benefits for customers.

In addition, there were a number of other positive regulatory developments during the year. In August, the Wisconsin Public Service Commission unanimously approved our proposed rate settlement. Base rates for all of our Wisconsin utilities will remain flat for 2018 and 2019. In total, this will keep base rates frozen for four years and essentially gives our customers price certainty through 2019.

As part of the agreement, we also expanded and made permanent certain pricing options for our large electric customers. These options will continue to help many of our customers grow their businesses, create jobs and reduce their energy costs.

In Illinois, we continue to make real progress on the Peoples Gas System Modernization Plan. On January 10 of this year – after an extensive review – the Illinois Commerce Commission issued an order that supports continuing the program at the scope, pace and investment level that we proposed. This program is critical to providing our Chicago customers with a natural gas delivery network that is modern, safe and reliable. For many years to come, we'll be replacing outdated natural gas piping – some of which was installed more than a century ago – with state-of-the-art materials.

Turning to Michigan, we obtained final regulatory approval last October for the construction of approximately 180 megawatts of new, natural gas-fired generation in the Upper Peninsula. Site preparation began within days of the commission order.

Gale E. Klappa, Chairman and Chief Executive Officer and Allen L. Leverett, President (currently on medical leave)

Our plan is to bring the new facilities into commercial service by mid-2019, and at that time or soon thereafter, we expect to retire our coal-fired power plant in Marquette, Michigan.

The project calls for a $266 million investment in reciprocating internal combustion engines. We call these RICE units. These units, which will be owned by one of our Michigan utilities, will provide an affordable, long-term power supply for customers in the Upper Peninsula, including the iron ore mine owned by Cleveland-Cliffs.

The RICE units are part of our new five-year capital investment plan. Totaling $11.8 billion, our updated capital plan is focused on reshaping our generation fleet for a clean, reliable future.

Our approach calls for greater reliance on natural gas and solar energy to meet customer demand for electricity. We plan to add another 50 megawatts of RICE generation in northern Wisconsin by 2021. We also have the option to invest up to $200 million in the Riverside power plant – a natural gas-fired facility being built by Alliant Energy.

And importantly, we plan to expand our portfolio of renewable generation. Over the past five years, utility-scale solar has increased in efficiency, and prices have dropped by approximately 70 percent. These factors make solar a cost-effective option for our customers – an option that also fits very well with our summer demand curve. We're in active discussions with developers, and we plan to file for approvals with the Wisconsin commission this spring.

As we look to the future, the company has a solid financial base and a strong pipeline of investment opportunities. With confidence in our future prospects, the board of directors raised the quarterly dividend at its January meeting to 55.25 cents a share – an increase of 6.25 percent over the previous rate. This will mark the 15th consecutive year that our company will reward our shareholders with higher dividends.

We continue to target a dividend payout ratio of 65 to 70 percent of earnings. We're in the middle of that range now, so I expect our dividend growth will continue to be in line with the growth in our earnings per share.

On a personal note, I know that all of you are interested in an update on Allen Leverett's recovery from the stroke he suffered last October. Allen, of course, succeeded me as chief executive in 2016.

As of the date of this writing, I can report to you that Allen is in good physical condition, and he continues to make progress in his recovery and rehabilitation work. Among other activities, Allen has been engaged in extensive speech therapy.

No specific time table has been established for his return to the company. So, as we announced a few months ago, I have agreed to serve as chief executive for as long as necessary.

Thank you for your confidence, your support and your investment in WEC Energy Group.

Sincerely,

Gale E. Klappa
Chairman and Chief Executive Officer
Feb. 28, 2018

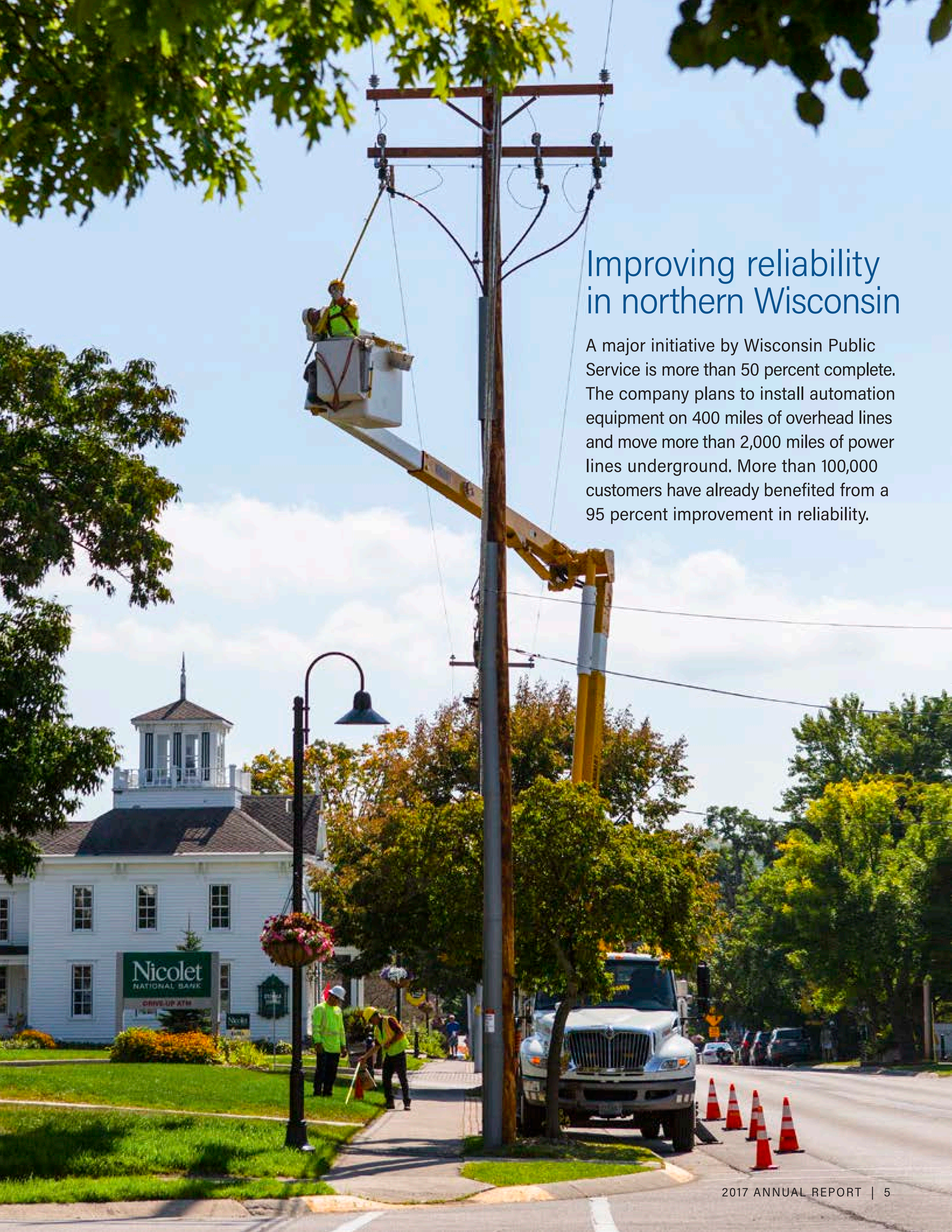
We Energies named America's **BEST** at keeping the lights on.

Upgrading Chicago's natural gas infrastructure

Peoples Gas is installing modern natural gas pipelines to serve the city of Chicago. This extensive program will provide a safer and more reliable system by replacing an outdated network of cast and ductile iron pipe – some installed over a century ago. To date, the program is approximately 24 percent complete.

Improving reliability in northern Wisconsin

A major initiative by Wisconsin Public Service is more than 50 percent complete. The company plans to install automation equipment on 400 miles of overhead lines and move more than 2,000 miles of power lines underground. More than 100,000 customers have already benefited from a 95 percent improvement in reliability.



An energy industry leader

WEC Energy Group is one of the nation's largest electric and natural gas delivery companies, with deep operational expertise, scale and financial resources to meet the Midwest region's energy needs.

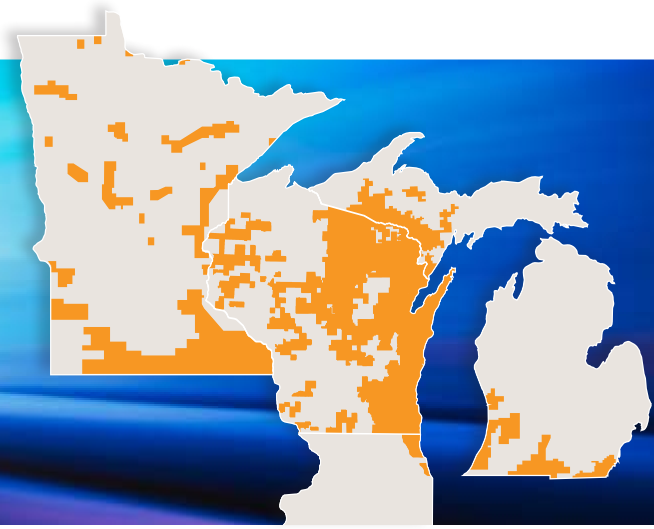
69,600 **miles**
of electric distribution

49,000 **miles**
of natural gas distribution and transmission lines
(including mains)

8,700 **megawatts**
of power capacity

8,000 **employees**

We provide vital services to more than
4.4 million
customers in Wisconsin, Illinois, Michigan and Minnesota.



WEC Energy Group includes the following companies:

We Energies delivers electricity, natural gas and steam to more than 2.2 million customers in Wisconsin.

Wisconsin Public Service delivers electricity and natural gas to more than 770,000 customers in northeast and central Wisconsin.

Michigan Gas Utilities delivers natural gas to more than 176,000 customers in southern and western Michigan.

Minnesota Energy Resources delivers natural gas to more than 235,000 customers in communities across Minnesota.

Peoples Gas delivers natural gas to more than 845,000 customers in the city of Chicago.

North Shore Gas delivers natural gas to more than 160,000 customers in Chicago's northern suburbs.

Upper Michigan Energy Resources delivers electricity and natural gas to more than 42,000 customers in Michigan's Upper Peninsula.

Bluewater Gas Storage, located in southeast Michigan, provides natural gas storage and hub services to We Energies and Wisconsin Public Service.

We Power designs, builds and owns modern, efficient power plants.

We® | WPS® Wisconsin Public Service | MICHIGAN GAS UTILITIES® | MINNESOTA ENERGY RESOURCES® | UPPER MICHIGAN ENERGY RESOURCES | PEOPLES GAS® | NORTH SHORE GAS® | Bluewater Gas Storage LLC | we power®

WEC Energy Group

2017 ANNUAL FINANCIAL STATEMENTS AND REVIEW OF OPERATIONS

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below:

Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
ATC Holdco	ATC Holdco, LLC
Bluewater	Bluewater Natural Gas Holding, LLC
Bostco	Bostco LLC
ERGSS	Elm Road Generating Station Supercritical, LLC
Integrys	Integrys Holding, Inc. (previously known as Integrys Energy Group, Inc.)
ITF	Integrys Transportation Fuels, LLC
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PDL	WPS Power Development, LLC
PELLC	Peoples Energy, LLC
PGL	The Peoples Gas Light and Coke Company
UMERC	Upper Michigan Energy Resources Corporation
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WECC	Wisconsin Energy Capital Corporation
WG	Wisconsin Gas LLC
Wispark	Wispark LLC
Wisvest	Wisvest LLC
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

Federal and State Regulatory Agencies	
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
IRS	United States Internal Revenue Service
MDEQ	Michigan Department of Environmental Quality
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources

Accounting Terms	
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
LIFO	Last-In, First-Out
OPEB	Other Postretirement Employee Benefits

Measurements	
Dth	Dekatherm
MDth	One thousand Dekatherms
MW	Megawatt
MWh	Megawatt-hour

Environmental Terms

Act 141	2005 Wisconsin Act 141
CAA	Clean Air Act
CO_2	Carbon Dioxide
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
GHG	Greenhouse Gas
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
SO_2	Sulfur Dioxide

Other Terms and Abbreviations

2006 Junior Notes	Integrys's 2006 Junior Subordinated Notes Due 2066
2007 Junior Notes	WEC Energy Group, Inc.'s 2007 Junior Subordinated Notes Due 2067
ALJ	Administrative Law Judge
ARRs	Auction Revenue Rights
CNG	Compressed Natural Gas
Compensation Committee	Compensation Committee of the Board of Directors
DATC	Duke-American Transmission Company
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
ERGS	Elm Road Generating Station
ER 1	Elm Road Generating Station Unit 1
ER 2	Elm Road Generating Station Unit 2
Exchange Act	Securities Exchange Act of 1934, as amended
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
LMP	Locational Marginal Price
MCPP	Milwaukee County Power Plant
Merger Agreement	Agreement and Plan of Merger, dated as of June 22, 2014, between Integrys Energy Group, Inc. and Wisconsin Energy Corporation
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
NYMEX	New York Mercantile Exchange
OCPP	Oak Creek Power Plant
OC 5	Oak Creek Power Plant Unit 5
OC 6	Oak Creek Power Plant Unit 6
OC 7	Oak Creek Power Plant Unit 7
OC 8	Oak Creek Power Plant Unit 8
Omnibus Stock Incentive Plan	WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016
PIPP	Presque Isle Power Plant
Point Beach	Point Beach Nuclear Power Plant
PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
QIP	Qualifying Infrastructure Plant
ROE	Return on Equity
RTO	Regional Transmission Organization
SMP	Natural Gas System Modernization Program
SMRP	System Modernization and Reliability Project
SSR	System Support Resource
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017
Tilden	Tilden Mining Company
Treasury Grant	Section 1603 Renewable Energy Treasury Grant
VAPP	Valley Power Plant

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements may be identified by reference to a future period or periods or by the use of terms such as "anticipates," "believes," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets," "will," or variations of these terms.

Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of capital projects, sales and customer growth, rate actions and related filings with regulatory authorities, environmental and other regulations and associated compliance costs, legal proceedings, dividend payout ratios, effective tax rate, pension and OPEB plans, fuel costs, sources of electric energy supply, coal and natural gas deliveries, remediation costs, liquidity and capital resources, and other matters.

Forward-looking statements are subject to a number of risks and uncertainties that could cause our actual results to differ materially from those expressed or implied in the statements. These risks and uncertainties include those described below:

- Factors affecting utility operations such as catastrophic weather-related damage, environmental incidents, unplanned facility outages and repairs and maintenance, and electric transmission or natural gas pipeline system constraints;
- Factors affecting the demand for electricity and natural gas, including political developments, unusual weather, changes in economic conditions, customer growth and declines, commodity prices, energy conservation efforts, and continued adoption of distributed generation by customers;
- The timing, resolution, and impact of rate cases and negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated operations;
- The ability to obtain and retain customers, including wholesale customers, due to increased competition in our electric and natural gas markets from retail choice and alternative electric suppliers, and continued industry consolidation;
- The timely completion of capital projects within budgets, as well as the recovery of the related costs through rates;
- The impact of federal, state, and local legislative and regulatory changes, including changes in rate-setting policies or procedures, deregulation and restructuring of the electric and/or natural gas utility industries, transmission or distribution system operation, the approval process for new construction, reliability standards, pipeline integrity and safety standards, allocation of energy assistance, and energy efficiency mandates;
- The uncertainty surrounding the recently enacted Tax Legislation, including implementing regulations and IRS interpretations, the amount to be returned to our ratepayers, and its impact, if any, on our or our subsidiaries' credit ratings;
- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting generation facilities and renewable energy standards, the enforcement of these laws and regulations, changes in the interpretation of permit conditions by regulatory agencies, and the recovery of associated remediation and compliance costs;
- Factors affecting the implementation of our generation reshaping plan, including related regulatory decisions, the cost of materials, supplies, and labor, and the feasibility of competing projects;
- Increased pressure on us by investors and other stakeholder groups to take more aggressive action to reduce future GHG emissions in order to limit future global temperature increases;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the availability of sources of fossil fuel, natural gas, purchased power, materials needed to operate environmental controls at our electric generating facilities, or water supply due to high demand, shortages, transportation problems, nonperformance by electric energy or natural gas suppliers under existing power purchase or natural gas supply contracts, or other developments;
- Changes in credit ratings, interest rates, and our ability to access the capital markets, caused by volatility in the global credit markets, our capitalization structure, and market perceptions of the utility industry, us, or any of our subsidiaries;
- Costs and effects of litigation, administrative proceedings, investigations, settlements, claims, and inquiries;
- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances, that could prevent us from paying our common stock dividends, taxes, and other expenses, and meeting our debt obligations;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our customers, counterparties, and affiliates to meet their obligations;

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading markets and fuel suppliers and transporters;
- The direct or indirect effect on our business resulting from terrorist attacks and cyber security intrusions, as well as the threat of such incidents, including the failure to maintain the security of personally identifiable information, the associated costs to protect our utility assets, technology systems, and personal information, and the costs to notify affected persons to mitigate their information security concerns;
- The financial performance of ATC and its corresponding contribution to our earnings, as well as the ability of ATC and DATC to obtain the required approvals for their transmission projects;
- The investment performance of our employee benefit plan assets, as well as unanticipated changes in related actuarial assumptions, which could impact future funding requirements;
- Factors affecting the employee workforce, including loss of key personnel, internal restructuring, work stoppages, and collective bargaining agreements and negotiations with union employees;
- Advances in technology that result in competitive disadvantages and create the potential for impairment of existing assets;
- The timing, costs, and anticipated benefits associated with the remaining integration efforts relating to the Integrys acquisition;
- The risk associated with the values of goodwill and other intangible assets and their possible impairment;
- Potential business strategies to acquire and dispose of assets or businesses, which cannot be assured to be completed timely or within budgets, and legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law;
- The timing and outcome of any audits, disputes, and other proceedings related to taxes;
- The ability to maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act, while both integrating and continuing to consolidate our enterprise systems;
- The effect of accounting pronouncements issued periodically by standard-setting bodies; and
- Other considerations disclosed elsewhere herein and in other reports we file with the SEC or in other publicly disseminated written documents.

We expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

BUSINESS OF THE COMPANY

WEC Energy Group, Inc. was incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. On June 29, 2015, Wisconsin Energy Corporation acquired 100% of the outstanding common shares of Integrys Energy Group and changed its name to WEC Energy Group, Inc. We maintain our principal executive offices in Milwaukee, Wisconsin.

In this report, when we refer to "us," "we," "our," or "ours," we are referring to WEC Energy Group, Inc. The term "utility" refers to the regulated activities of our electric and natural gas utility companies, while the term "non-utility" refers to the activities of our electric and natural gas utility companies that are not regulated, as well as We Power and Bluewater. The term "nonregulated" refers to activities at our Corporate and Other Segment.

Our wholly owned subsidiaries are primarily engaged in the business of providing regulated electricity service in Wisconsin and Michigan and regulated natural gas service in Wisconsin, Illinois, Michigan and Minnesota. In addition, we have an approximate 60% equity interest in ATC, an electric transmission company operating primarily in four states. At December 31, 2017, we conducted our operations in the six reportable segments discussed below.

Wisconsin Segment: The Wisconsin segment includes the electric and natural gas utility and non-utility operations of WE, WG, WPS, and UMERC. UMERC became operational effective January 1, 2017, and holds the electric and natural gas distribution assets previously held by WE and WPS in the Upper Peninsula of Michigan.

At December 31, 2017, these companies served approximately 1,607,500 electric customers and 1,450,800 natural gas customers. This segment also includes steam service to approximately 400 WE steam customers in metropolitan Milwaukee, Wisconsin.

Illinois Segment: The Illinois segment includes the natural gas utility and non-utility operations of PGL and NSG. The approximately 1,006,000 natural gas customers served by PGL and NSG at December 31, 2017, were located in Chicago and the northern suburbs of Chicago. PGL also owns and operates a 38.3 Bcf natural gas storage field in central Illinois.

Other States Segment: The other states segment includes the natural gas utility and non-utility operations of MERC and MGU. These companies served approximately 411,700 natural gas customers at December 31, 2017, with MERC serving customers in various cities and communities throughout Minnesota, and MGU serving customers in southern and western Michigan.

Electric Transmission Segment: The electric transmission segment includes our approximate 60% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. ATC owns, maintains, monitors, and operates electric transmission systems primarily in Wisconsin, Michigan, Illinois, and Minnesota.

In addition, we own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission related projects outside of ATC's traditional footprint. As of December 31, 2017, we had an investment of $37.6 million in ATC Holdco.

Non-Utility Energy Infrastructure Segment: The non-utility energy infrastructure segment includes the operations of We Power and Bluewater, following its acquisition in June 2017. We Power, through wholly owned subsidiaries, owns and leases to WE, certain generating facilities. PWGS 1 and PWGS 2, both natural gas-fired generating units, are being leased to WE under long-term leases that run for 25 years. ER 1 and ER 2, both coal-fired generating units, are being leased to WE under long-term leases that run for 30 years. Bluewater owns natural gas storage facilities in southeast Michigan that can provide approximately one-third of the current storage needs for the natural gas operations of WE, WG, and WPS.

Corporate and Other Segment: The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, and the PELLC holding company, as well as the operations of Wispark, Bostco, Wisvest, WECC, WBS, PDL, and ITF.

Wispark develops and invests in real estate, and had $49.5 million in real estate holdings at December 31, 2017. WBS is a wholly owned centralized service company that provides administrative and general support services to our regulated utilities, as well as certain services to our nonregulated entities. PDL owns distributed renewable solar projects.

We completed the sale of ITF, which provided CNG products and services in multiple states, in February 2016. In April 2016, as part of the sale of WE's Milwaukee County Power Plant, we sold the chilled water generation and distribution assets of Wisvest, which provided chilled water services to the Milwaukee Regional Medical Center. Bostco was originally formed to develop and invest in real estate and in March 2017, we sold the remaining real estate holdings of Bostco. WECC was originally formed to invest in non-utility projects such as low income housing developments, but no longer has significant operations.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

INTRODUCTION

We are a diversified holding company with natural gas and electric utility operations (serving customers in Wisconsin, Illinois, Michigan, and Minnesota), an approximately 60% equity ownership interest in American Transmission Company LLC (ATC) (a for-profit electric transmission company regulated by the FERC and certain state regulatory commissions), and non-utility energy infrastructure operations through We Power and Bluewater, which owns underground natural gas storage facilities in Michigan.

CORPORATE STRATEGY

Our goal is to continue to build and sustain long-term value for our shareholders and customers by focusing on the fundamentals of our business: reliability; operating efficiency; financial discipline; customer care; and safety.

Reshaping Our Generation Fleet

The planned reshaping of our generation fleet will balance reliability and customer cost with environmental stewardship. Taken as a whole, this plan should reduce costs to customers, preserve fuel diversity, and lower carbon emissions. Generation reshaping includes retiring older fossil fuel generation units, building state-of-the-art natural gas generation, and investing in cost-effective zero-carbon generation with a goal of reducing CO_2 emissions by approximately 40% below 2005 levels by 2030. We expect to retire approximately 1,800 MW of coal generation by 2020, and add additional natural gas-fired generating units and renewable generation, including utility-scale solar projects. See Note 5, Property, Plant, and Equipment, for information related to the planned retirements of certain of our coal-fueled power plants.

Reliability

We have made significant reliability-related investments in recent years, and plan to continue strengthening and modernizing our generation fleet and distribution networks to further improve reliability. Our investments, coupled with our commitment to operating efficiency and customer care, resulted in We Energies being recognized by PA Consulting Group, an independent consulting firm, as the most reliable utility in the United States in 2017 and, for the seventh year in a row, as the most reliable utility in the Midwest.

Below are a few examples of reliability projects that are currently underway.

- Upper Michigan Energy Resources Corporation (UMERC), our Michigan electric and natural gas utility, is moving forward with its long-term generation solution for electric reliability in the Upper Peninsula of Michigan. The plan calls for UMERC to construct and operate approximately 180 MW of natural gas-fueled generation located in the Upper Peninsula. The new generation is expected to achieve commercial operation in 2019 and provide the region with affordable, reliable electricity that generates less emissions than the Presque Isle Power Plant (PIPP). This should allow for the retirement of PIPP no later than 2020. We began site preparation work for this new generation in October 2017. For more information, see Note 23, Regulatory Environment.
- The Peoples Gas Light and Coke Company continues to work on its Natural Gas System Modernization Program, which primarily involves replacing old cast and ductile iron pipes and facilities in Chicago’s natural gas delivery system with modern polyethylene pipes to reinforce the long-term safety and reliability of the system.
- Wisconsin Public Service Corporation (WPS) continues work on its System Modernization and Reliability Project, which involves modernizing parts of its electric distribution system, including burying or upgrading lines. The project focuses on constructing facilities to improve the reliability of electric service WPS provides to its customers. WPS, Wisconsin Electric Power Company and Wisconsin Gas LLC also continue to upgrade their electric and natural gas distribution systems to enhance reliability.

Operating Efficiency

We continually look for ways to optimize the operating efficiency of our company. For example, we made further investments at the Elm Road Generating Station in 2017 to enable the facility to burn coal from the Powder River Basin located in the western United States. The plant was originally designed to burn coal mined from the eastern United States. This project is creating flexibility and has enabled the plant to operate at lower costs, placing it in a better position to be called upon in the MISO Energy Markets, resulting in lower fuel costs for our customers.

We also made progress on our Advanced Metering Infrastructure program, replacing aging meter-reading equipment on both our network and customer property. An integrated system of smart meters, communication networks, and data management programs enables two-way communication between our utilities and our customers. This program reduces the manual effort for disconnects and reconnects and enhances outage management capabilities.

We continue to focus on integrating and improving business processes and consolidating our IT infrastructure across all of our companies. We expect these efforts to continue to drive operational efficiency and to put us in position to effectively support plans for future growth.

Financial Discipline

A strong adherence to financial discipline is essential to meeting our earnings projections and maintaining a strong balance sheet, stable cash flows, a growing dividend, and quality credit ratings.

We follow an asset management strategy that focuses on investing in and acquiring assets consistent with our strategic plans, as well as disposing of assets, including property, plants, equipment, and entire business units, that are no longer strategic to operations, are not performing as intended, or have an unacceptable risk profile.

- See Note 2, Acquisitions, for information about our acquisitions of natural gas storage facilities in Michigan and a portion of a wind energy generation facility in Wisconsin.
- See Note 3, Dispositions, for information on the sale of Integrys Transportation Fuels, LLC, the Milwaukee County Power Plant, certain assets of Wisvest LLC, and Bostco LLC's real estate holdings.

Our investment focus remains in our regulated utility and non-utility energy infrastructure businesses, as well as our investment in ATC. We expect total capital expenditures for our regulated utility and non-utility energy infrastructure businesses to be almost $12 billion from 2018 to 2022. Specific projects are discussed in more detail below under Liquidity and Capital Resources.

From 2018 to 2022, we expect capital contributions to ATC and ATC Holdco to be approximately $280 million. ATC Holdco is a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. Capital investments at ATC and ATC Holdco will be funded utilizing these capital contributions, in addition to cash generated from operations and debt. We currently forecast that our share of ATC's and ATC Holdco's projected capital expenditures over the next five years will be $1.3 billion inside the traditional ATC footprint and $300 million outside of the traditional ATC footprint.

Exceptional Customer Care

Our approach is driven by an intense focus on delivering exceptional customer care every day. We strive to provide the best value for our customers by embracing constructive change, demonstrating personal responsibility for results, leveraging our capabilities and expertise, and using creative solutions to meet or exceed our customers' expectations.

One example of how we obtain feedback from our customers is through our "We Care" calls, through which employees of our utility subsidiaries contact customers after a completed service call. Customer satisfaction is a priority, and making "We Care" calls is one of the main methods we use to gauge our performance to improve customer satisfaction.

Safety

We have a long-standing commitment to both workplace and public safety, and under our "Target Zero" mission, we have an ultimate goal of zero incidents, accidents, and injuries. We also set goals around injury-prevention activities that raise awareness and facilitate conversations about employee safety. Our corporate safety program provides a forum for addressing employee concerns, training employees and contractors on current safety standards, and recognizing those who demonstrate a safety focus.

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our consolidated results:

(in millions, except per share data)	Year Ended December 31 2017	2016	2015
Wisconsin	**$ 1,065.9**	$ 1,027.0	$ 884.2
Illinois	**273.0**	239.6	78.1
Other states	**54.2**	49.9	6.0
Non-utility energy infrastructure	**400.5**	375.6	373.4
Corporate and other	**(8.4)**	(10.0)	(91.2)
Total operating income	**1,785.2**	1,682.1	1,250.5
Equity in earnings of transmission affiliates	**154.3**	146.5	96.1
Other income, net	**64.6**	80.8	58.9
Interest expense	**415.7**	402.7	331.4
Income before income taxes	**1,588.4**	1,506.7	1,074.1
Income tax expense	**383.5**	566.5	433.8
Preferred stock dividends of subsidiary	**1.2**	1.2	1.8
Net income attributed to common shareholders	**$ 1,203.7**	$ 939.0	$ 638.5
Diluted earnings per share	**$ 3.79**	$ 2.96	$ 2.34

2017 Compared with 2016

Earnings increased $264.7 million during 2017, compared with 2016. The significant factors impacting the increase in earnings were:

- A $206.7 million one-time net reduction in income tax expense related to the revaluation of our deferred taxes primarily on our non-utility energy infrastructure and corporate and other segments at December 31, 2017, as a result of the enactment of the Tax Legislation.
- A $38.9 million pre-tax ($23.3 million after tax) increase in operating income at the Wisconsin segment, driven by lower operating expenses. A decrease in electric margins, driven by lower sales volumes, partially offset the decrease in operating expenses.
- A $33.4 million pre-tax ($20.0 million after tax) increase in operating income at the Illinois segment. The increase was driven by higher natural gas margins at PGL due to continued capital investment in the SMP project under its QIP rider and lower operating expenses.
- A $24.9 million pre-tax ($14.9 million after tax) increase in operating income at the non-utility energy infrastructure segment. The increase was driven by higher revenues in connection with capital additions to the plants We Power owns and leases to WE and the inclusion of the operations of Bluewater following its acquisition on June 30, 2017.

These increases in earnings were partially offset by a $16.2 million pre-tax ($9.7 million after-tax) decrease in other income, net. The decrease was primarily driven by the year-over-year impact of the gains recognized in 2016 related to the repurchase of a portion of Integrys's 2006 Junior Notes and the sale of certain assets of Wisvest. See Note 3, Dispositions, for information on the Wisvest sale.

2016 Compared with 2015

Earnings increased $300.5 million in 2016, driven by a $201.7 million increase in earnings due to the inclusion of a full year of Integrys's results for 2016, compared to six months of Integrys's results for 2015. Integrys was acquired on June 29, 2015. See Note 2, Acquisitions, for more information.

The most significant factor driving the remaining $98.8 million increase in earnings was a $104.1 million pre-tax ($80.1 million after tax) decrease in acquisition costs in 2016.

Non-GAAP Financial Measure

The discussions below address the operating income contribution of each of our segments and include financial information prepared in accordance with GAAP, as well as electric margins and natural gas margins, which are not measures of financial performance under GAAP. Electric margin (electric revenues less fuel and purchased power costs) and natural gas margin (natural gas revenues less cost of natural gas sold) are non-GAAP financial measures because they exclude other operation and maintenance expense, depreciation and amortization, and property and revenue taxes.

We believe that electric and natural gas margins provide a more meaningful basis for evaluating utility operations than operating revenues since the majority of prudently incurred fuel and purchased power costs, as well as prudently incurred natural gas costs, are passed through to customers in current rates. As a result, management uses electric and natural gas margins internally when assessing the operating performance of our segments as these measures exclude the majority of revenue fluctuations caused by changes in these expenses. Similarly, the presentation of electric and natural gas margins herein is intended to provide supplemental information for investors regarding our operating performance.

Our electric margins and natural gas margins may not be comparable to similar measures presented by other companies. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of our segment operating performance. Operating income for each of the last three fiscal years for each of our segments is presented in the "Consolidated Earnings" table above.

Each applicable segment operating income discussion below includes a table that provides the calculation of electric margins and natural gas margins, as applicable, along with a reconciliation to segment operating income.

WISCONSIN SEGMENT CONTRIBUTION TO OPERATING INCOME

For the periods presented in this report, our Wisconsin operations included operations of WE and WG for all periods, operations for WPS beginning July 1, 2015, due to the acquisition of Integrys and its subsidiaries, and operations for UMERC beginning January 1, 2017, due to the transfer of customers and assets in the Upper Peninsula of Michigan from WE and WPS.

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
Electric revenues	**$ 4,559.0**	$ 4,628.1	$ 4,068.5
Fuel and purchased power	**1,467.0**	1,473.1	1,369.3
Total electric margins	**3,092.0**	3,155.0	2,699.2
Natural gas revenues	**1,270.2**	1,177.6	1,122.6
Cost of natural gas sold	**701.8**	621.2	640.5
Total natural gas margins	**568.4**	556.4	482.1
Total electric and natural gas margins	**3,660.4**	3,711.4	3,181.3
Other operation and maintenance	**1,912.5**	2,025.4	1,741.0
Depreciation and amortization	**523.9**	496.6	408.6
Property and revenue taxes	**158.1**	162.4	147.5
Operating income	**$ 1,065.9**	$ 1,027.0	$ 884.2

The following table shows a breakdown of other operation and maintenance:

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
Operation and maintenance not included in line items below	**$ 822.6**	$ 881.9	$ 744.2
We Power (1)	**513.0**	513.2	510.7
Transmission (2)	**407.4**	423.2	341.3
Regulatory amortizations and other pass through expenses (3)	**158.1**	157.4	144.8
Earnings sharing mechanisms	**2.9**	24.4	—
Other	**8.5**	25.3	—
Total other operation and maintenance	**$ 1,912.5**	$ 2,025.4	$ 1,741.0

(1) Represents costs associated with the We Power generation units, including operating and maintenance costs incurred by WE, as well as the lease payments that are billed from We Power to WE and then recovered in WE's rates. During 2017, 2016, and 2015, $535.1 million, $528.4 million, and $483.4 million, respectively, of both lease and operating and maintenance costs were billed to or incurred by WE, with the difference in costs billed or incurred and expenses recognized, either deferred or deducted from the regulatory asset.

(2) The PSCW has approved escrow accounting for ATC and MISO network transmission expenses for our Wisconsin electric utilities. As a result, WE and WPS defer as a regulatory asset or liability the differences between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding. During 2017, 2016, and 2015, $451.4 million, $486.0 million, and $388.6 million, respectively, of costs were billed by transmission providers to our electric utilities.

(3) Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on operating income.

The following tables provide information on delivered volumes by customer class and weather statistics:

	Year Ended December 31 MWh *(in thousands)*		
Electric Sales Volumes	**2017**	**2016**	**2015**
Customer class			
Residential	**10,636.3**	10,998.9	9,218.9
Small commercial and industrial *	**12,932.1**	13,113.1	10,889.2
Large commercial and industrial *	**12,822.0**	13,418.6	11,545.8
Other	**175.6**	172.2	162.6
Total retail *	**36,566.0**	37,702.8	31,816.5
Wholesale	**3,768.0**	3,704.6	2,588.1
Resale	**9,000.3**	8,761.6	9,077.1
Total sales in MWh *	**49,334.3**	50,169.0	43,481.7

* Includes distribution sales for customers who have purchased power from an alternative electric supplier in Michigan.

	Year Ended December 31 Therms *(in millions)*		
Natural Gas Sales Volumes	**2017**	**2016**	**2015**
Customer class			
Residential	**1,039.4**	1,014.9	859.4
Commercial and industrial	**643.6**	610.5	527.4
Total retail	**1,683.0**	1,625.4	1,386.8
Transport	**1,316.4**	1,270.6	994.2
Total sales in therms	**2,999.4**	2,896.0	2,381.0

	Year Ended December 31 Degree Days		
Weather	**2017**	**2016**	**2015**
WE and WG (1)			
Heating (6,574 normal)	**5,908**	6,068	6,468
Cooling (714 normal)	**772**	991	622
WPS (2)			
Heating (7,377 normal)	**6,942**	6,715	2,215
Cooling (499 normal)	**450**	572	396
UMERC (3)			
Heating (8,368 normal)	**8,145**	N/A	N/A
Cooling (324 normal)	**235**	N/A	N/A

(1) Normal degree days are based on a 20-year moving average of monthly temperatures from Mitchell International Airport in Milwaukee, Wisconsin.

(2) Normal degree days are based on a 20-year moving average of monthly temperatures from the Green Bay, Wisconsin weather station. Degree days for 2015 have been included for the period from July 1, 2015, through December 31, 2015.

(3) Normal degree days are based on a 20-year moving average of monthly temperatures from the Iron Mountain, Michigan weather station.

2017 Compared with 2016

Electric Utility Margins

Electric utility margins at the Wisconsin segment decreased $63.0 million during 2017, compared with 2016. The significant factors impacting the lower electric utility margins were:

- A $72.6 million decrease related to lower sales volumes during 2017, primarily driven by unfavorable weather as well as lower overall retail use per customer. Cooler summer and warmer winter weather in 2017, as well as an additional day of sales during 2016 due to leap year, contributed to the decrease. As measured by cooling degree days, 2017 was 22.1% and 21.3% cooler than 2016 in the Milwaukee and Green Bay areas, respectively. As measured by heating degree days, 2017 was 2.6% warmer than the same period in 2016 in the Milwaukee area.
- A $25.9 million decrease related to SSR payments WE refunded to MISO as directed by a FERC order received in October 2017. The FERC order reduced the costs eligible for reimbursement to WE for the operation and maintenance of its PIPP units under an SSR agreement between MISO and WE. A portion of these payments was returned to WE through the MISO allocation process and reduced transmission expense as discussed below. See Note 23, Regulatory Environment, for more information.
- A $3.5 million decrease in steam margins driven by the sale of the MCPP in April 2016. See Note 3, Dispositions, for more information.
- A $3.3 million period-over-period negative impact from collections of fuel and purchased power costs compared with costs approved in rates. Under the Wisconsin fuel rules, the margins of our electric utilities are impacted by under- or over-collections of certain fuel and purchased power costs that are less than a 2% price variance from the costs included in rates, and the remaining variance that exceeds the 2% variance is deferred.

These decreases in margins were partially offset by $36.5 million of lower capacity payments to a counterparty during 2017, related to improved contract terms.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment increased $12.0 million during 2017, compared with 2016. The most significant factor impacting the higher natural gas utility margins was higher retail sales volumes, primarily driven by higher overall retail use per customer and customer growth. The higher margins were partially offset by an additional day of sales during 2016 due to leap year.

Operating Income

Operating income at the Wisconsin segment increased $38.9 million during 2017, compared with 2016. This increase was driven by $89.9 million of lower operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenue taxes), partially offset by the $51.0 million net decrease in margins discussed above.

The Wisconsin segment experienced lower overall operating expenses related to synergy savings resulting from the Integrys acquisition. The significant factors impacting the decrease in operating expenses during 2017, compared with 2016, which were due in part to synergy savings, were:

- A $29.1 million decrease in electric and natural gas distribution expenses, primarily related to lower metering costs and other cost savings.
- A $21.5 million decrease in expenses related to the earnings sharing mechanisms in place at WE and WG. See the PSCW conditions of approval related to the Integrys acquisition in Note 2, Acquisitions, for more information.
- A $16.8 million decrease in expenses related to charitable projects supporting our customers and the communities within our service territories.
- A $15.8 million decrease in transmission expenses, driven by a FERC order to reduce SSR costs related to PIPP, as discussed under electric utility margins.
- An $11.5 million decrease in expenses related to an information technology project completed in 2016 to improve the billing, call center, and credit collection functions of certain WEC Energy Group subsidiaries. Lower expenses were due in part to a decrease in asset usage charges from WBS, driven by the transfer of this project from WBS to certain WEC Energy Group subsidiaries, including WPS, during 2017. The portion of these lower expenses related to the transfer is offset through higher depreciation and amortization, discussed below.

- A $10.5 million decrease in operation and maintenance expenses at our plants, primarily related to the seasonal operation of the Pleasant Prairie power plant during 2017, lower operating costs at the plants, the timing of planned outages and maintenance, and the sale of the MCPP in April 2016. See Note 3, Dispositions, for more information on the sale of the MCPP. These decreases were partially offset by severance costs related to plant retirement. See Note 5, Property, Plant, and Equipment, for more information on the plants to be retired.
- A $5.7 million decrease in customer service expenses, partially related to lower contracted meter reading rates and cost savings.

These decreases in operating expenses were partially offset by:

- A $27.3 million increase in depreciation and amortization, driven by an overall increase in utility plant in service, the completion of the ReACTTM multi-pollutant control system at Weston Unit 3 during the fourth quarter of 2016, and WBS's transfer of the information technology project to WPS during 2017.
- A $10.9 million gain recorded in April 2016 related to the sale of the MCPP. See Note 3, Dispositions, for more information on the sale of the MCPP.

2016 Compared with 2015

Electric Utility Margins

Electric utility margins at the Wisconsin segment increased $455.8 million during 2016, compared with 2015. The increase was primarily driven by a $386.4 million margin contribution from WPS during the first six months of 2016, compared with no margin contribution from WPS for the first six months of 2015.

The significant factors impacting the remaining $69.4 million increase in electric utility margins at the Wisconsin segment were:

- A $50.4 million increase related to higher retail sales volumes during 2016, primarily driven by warmer summer weather. As measured by cooling degree days, 2016 was 59.3% warmer than 2015 in the Milwaukee area.
- The expiration of $12.5 million of bill credits refunded to customers in 2015 related to the Treasury Grant WE received in connection with its biomass facility.
- An $11.3 million increase in the last six months of 2016 as a result of WPS's PSCW rate order, effective January 1, 2016. See Note 23, Regulatory Environment, for more information.

These increases were partially offset by a $12.9 million decrease in wholesale margins driven by a reduction in capacity sales year-over-year at WE in addition to a reduction in sales volumes at WPS for the second half of 2016, compared with the same period in 2015. Certain wholesale customers have provisions in their contracts, which allowed them to reduce the amount of energy we provided to them.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment increased $74.3 million during 2016, compared with 2015. The increase in natural gas utility margins was driven by a $63.6 million margin contribution from WPS during the first six months of 2016, compared with no margin contribution from WPS for the first six months of 2015.

The most significant factor impacting the remaining $10.7 million increase in natural gas utility margins at the Wisconsin segment was an $18.1 million net increase from both WG's rate order effective January 1, 2016, and a partially offsetting negative impact from WPS's rate order during the last six months of 2016. See Note 23, Regulatory Environment, for more information. This net increase was partially offset by a $3.2 million decrease related to lower sales volumes during 2016, primarily driven by warmer winter weather. As measured by heating degree days, 2016 was 6.2% warmer than 2015 in the Milwaukee area.

Operating Income

Operating income at the Wisconsin segment increased $142.8 million during 2016, compared with 2015. The increase was driven by the $530.1 million increase in margins discussed above, partially offset by $387.3 million of higher operating expenses. Higher operating expenses were driven by $321.6 million of operating expenses from WPS during the first six months of 2016, compared with no operating expenses from WPS for the first six months of 2015.

The significant factors impacting the remaining $65.7 million increase in operating expenses during 2016, compared with 2015, at the Wisconsin segment were:

- A $27.0 million increase in depreciation and amortization, driven by an overall increase in utility plant in service. In November 2015, WG completed the Western Gas lateral project, and WE completed the conversion of the fuel source for VAPP from coal to natural gas.
- A $25.3 million increase in expenses related to charitable projects supporting our customers and the communities within our service territories.
- A $24.4 million expense related to the earnings sharing mechanisms in place at WE and WG, effective January 1, 2016.

These increases in operating expenses were partially offset by a $16.4 million positive impact at WE from the sale of the MCPP in April 2016, including a gain on sale and lower operating costs in 2016.

ILLINOIS SEGMENT CONTRIBUTION TO OPERATING INCOME

We did not have any operations in Illinois until our acquisition of Integrys on June 29, 2015. Since the majority of PGL and NSG customers use natural gas for heating, operating income is sensitive to weather and is generally higher during the winter months.

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
Natural gas revenues	**$ 1,355.5**	$ 1,242.2	$ 503.4
Cost of natural gas sold	**438.9**	365.2	133.2
Total natural gas margins	**916.6**	877.0	370.2
Other operation and maintenance	**471.1**	485.1	219.6
Depreciation and amortization	**152.6**	134.0	63.3
Property and revenue taxes	**19.9**	18.3	9.2
Operating income	**$ 273.0**	$ 239.6	$ 78.1

The following table shows a breakdown of other operation and maintenance:

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
Operation and maintenance not included in the line items below	**$ 368.4**	$ 385.3	$ 196.0
Riders *	**98.1**	82.3	20.2
Regulatory amortizations *	**1.0**	2.7	1.3
Other	**3.6**	14.8	2.1
Total other operation and maintenance	**$ 471.1**	$ 485.1	$ 219.6

* These riders and regulatory amortizations are substantially offset in margins and therefore do not have a significant impact on operating income.

The following tables provide information on delivered volumes by customer class and weather statistics:

	Therms *(in millions)*		
Natural Gas Sales Volumes	**2017**	**2016**	**2015**
Customer Class			
Residential	**886.2**	905.6	300.7
Commercial and industrial	**183.6**	187.6	63.2
Total retail	**1,069.8**	1,093.2	363.9
Transport	**858.8**	855.3	328.4
Total sales in therms	**1,928.6**	1,948.5	692.3

	Degree Days		
Weather *	**2017**	**2016**	**2015**
Heating (6,110 normal)	**5,470**	5,713	1,813

* Normal heating degree days are based on a 12-year moving average of monthly temperatures from Chicago's O'Hare Airport.

2017 Compared with 2016

Natural Gas Utility Margins

Natural gas utility margins, net of the $15.8 million impact of the riders referenced in the table above, increased $23.8 million during 2017, compared with 2016. The increase was primarily driven by an increase in revenue at PGL due to continued capital investment in the SMP project under its QIP rider. PGL currently recovers the costs related to the SMP through a surcharge on customer bills pursuant to an ICC approved QIP rider, which is in effect through 2023.

Operating Income

Operating income at the Illinois segment increased $33.4 million during 2017, compared with 2016. This increase was due to the $23.8 million net increase in margins discussed above and a $9.6 million decrease in operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes), net of the impact of the riders referenced in the table above. The significant factors impacting the decrease in operating expenses were:

- A $21.1 million decrease in benefit related expenses driven by lower pension costs.
- A $9.8 million decrease in expenses related to charitable projects supporting our customers and the communities within our service territories.
- A $6.0 million decrease in expenses related to an information technology project created to improve the billing, call center, and credit collection functions of certain WEC Energy Group subsidiaries. Lower expenses were primarily due to a decrease in asset usage charges from WBS, driven by the transfer of this project from WBS to certain WEC Energy Group subsidiaries, including PGL and NSG, during 2017. Lower expenses related to the transfer are offset through higher depreciation and amortization, discussed below.

These decreases were partially offset by:

- An $18.6 million increase in depreciation and amortization expense, driven by continued capital investment at PGL in the SMP project and the transfer of the information technology project to PGL and NSG in 2017.
- A $3.4 million increase in natural gas distribution expenses, driven by increased repair activity in 2017.

2016 Compared with 2015

Natural Gas Utility Margins

Natural gas utility margins at the Illinois segment increased $506.8 million during 2016, compared with 2015. The increase was primarily driven by a $467.8 million margin contribution from the Illinois segment during the first six months of 2016, compared to no margin contribution from this segment for the first six months of 2015.

The significant factors impacting the remaining $39.0 million increase in natural gas utility margins at the Illinois segment were:

- A $26.3 million increase in margins related to the riders referenced in the table above during the last six months of 2016, compared with the last six months of 2015.
- A $10.8 million increase in revenue at PGL due to continued capital investment in projects under its QIP rider.

Operating Income

Operating income at the Illinois segment increased $161.5 million during 2016, compared with 2015. The increase was primarily driven by the $506.8 million increase in margin discussed above, partially offset by:

- Operating expenses of $308.2 million during the first six months of 2016, compared with no operating expenses during the first six months of 2015.
- A $26.3 million increase in other operation and maintenance expenses related to the riders referenced in the table above during the last six months of 2016, compared with the last six months of 2015.
- A $9.7 million increase in other operation and maintenance expenses during the last six months of 2016 compared with the last six months of 2015, due to an increase in expenses related to charitable projects supporting our customers and the communities within our service territories.

OTHER STATES SEGMENT CONTRIBUTION TO OPERATING INCOME

We did not have any operations in this segment until our acquisition of Integrys on June 29, 2015. Since the majority of MERC and MGU customers use natural gas for heating, operating income is sensitive to weather and is generally higher during the winter months.

	Year Ended December 31		
(in millions)	2017	2016	2015
Natural gas revenues	**$ 411.2**	$ 376.5	$ 149.3
Cost of natural gas sold	**215.3**	182.3	76.9
Total natural gas margins	**195.9**	194.2	72.4
Other operation and maintenance	**101.3**	110.1	50.0
Depreciation and amortization	**24.8**	21.1	10.0
Property and revenue taxes	**15.6**	13.1	6.4
Operating income	**$ 54.2**	$ 49.9	$ 6.0

The following table shows a breakdown of other operation and maintenance:

	Year Ended December 31		
(in millions)	2017	2016	2015
Operation and maintenance not included in line items below	**$ 78.3**	$ 86.4	$ 43.2
Regulatory amortizations and other pass through expenses *	**23.0**	23.6	6.7
Other	**—**	0.1	0.1
Total other operation and maintenance	**$ 101.3**	$ 110.1	$ 50.0

* Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on operating income.

The following tables provide information on delivered volumes by customer class and weather statistics:

	Therms *(in millions)*		
Natural Gas Sales Volumes	2017	2016	2015
Customer Class			
Residential	**285.6**	278.5	84.7
Commercial and industrial	**199.4**	178.2	60.9
Total retail	**485.0**	456.7	145.6
Transport	**693.3**	696.2	279.6
Total sales in therms	**1,178.3**	1,152.9	425.2

	Degree Days		
Weather *	2017	2016	2015
MERC			
Heating (7,907 normal)	**7,625**	7,188	2,563
MGU			
Heating (6,244 normal)	**5,707**	5,712	1,822

* Normal heating degree days for MERC and MGU are based on a 20-year moving average and 15-year moving average, respectively, of monthly temperatures from various weather stations throughout their respective territories.

2017 Compared with 2016

Operating Income

Operating income at the other states segment increased $4.3 million during 2017, compared with 2016. The increase was primarily driven by lower operation and maintenance expense due to effective cost control measures, partially offset by higher depreciation and amortization due to an increase in capital investment.

2016 Compared with 2015

Natural Gas Utility Margins

Natural gas utility margins at the other states segment increased $121.8 million during 2016, compared with 2015. The increase was primarily driven by a $110.4 million margin contribution from the other states segment during the first six months of 2016, compared to no margin contribution from this segment for the first six months of 2015.

The significant factors impacting the remaining $11.4 million increase in natural gas utility margins at the other states segment were:

- A $3.9 million increase in the last six months of 2016 as a result of various rate orders. An interim rate order for MERC was effective January 1, 2016, and accounted for $2.5 million of the rate increase. The MGU rate order was also effective January 1, 2016, and accounted for $1.4 million of the rate increase. See Note 23, Regulatory Environment, for more information.
- A $3.0 million increase related to higher sales volumes during the last six months of 2016, driven by colder weather. As measured by heating degree days, the last six months of 2016 were 11.5% colder than the last six months of 2015 at MGU and 5.7% colder than the last six months of 2015 at MERC.
- A $1.6 million increase related to the MERC conservation improvement program financial incentive as a result of exceeding certain energy savings goals.

Operating Income

Operating income at the other states segment increased $43.9 million during 2016, compared with 2015. The increase was driven by the $121.8 million increase in margins discussed above, partially offset by $77.9 million of higher operating expenses. Higher operating expenses were driven primarily by $76.3 million of operating expenses from the other states segment during the first six months of 2016, compared with no operating expenses during the first six months of 2015.

NON-UTILITY ENERGY INFRASTRUCTURE SEGMENT CONTRIBUTION TO OPERATING INCOME

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
Operating income	**$ 400.5**	$ 375.6	$ 373.4

2017 Compared with 2016

Operating income at the non-utility energy infrastructure segment increased $24.9 million during 2017, compared with 2016. Bluewater, which was acquired on June 30, 2017, contributed $8.4 million to 2017 operating income. The remaining increase of $16.5 million was driven by higher revenues in connection with capital additions to the plants We Power owns and leases to WE. See Note 2, Acquisitions, for more information on the acquisition of Bluewater and Note 19, Segment Information, for information on the change in segment name.

2016 Compared with 2015

Operating income at the non-utility energy infrastructure segment increased $2.2 million during 2016, compared with 2015. This increase was primarily related to higher revenues in connection with capital additions to the plants We Power owns and leases to WE.

CORPORATE AND OTHER SEGMENT CONTRIBUTION TO OPERATING INCOME

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
Operating loss	**$ (8.4)**	$ (10.0)	$ (91.2)

2017 Compared with 2016

The operating loss at the corporate and other segment decreased $1.6 million during 2017, compared with 2016, driven by $3.5 million of costs incurred in 2016 related to the acquisition of Integrys. See Note 2, Acquisitions, for more information regarding costs associated with the acquisition.

2016 Compared with 2015

The operating loss at the corporate and other segment decreased $81.2 million during 2016, compared with 2015, driven by a reduction in costs related to the acquisition of Integrys.

ELECTRIC TRANSMISSION SEGMENT OPERATIONS

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
Equity in earnings of transmission affiliates	**$ 154.3**	$ 146.5	$ 96.1

2017 Compared with 2016

Earnings from our ownership interests in transmission affiliates increased $7.8 million during 2017, compared with 2016. The lower earnings during 2016 as compared to 2017 were primarily the result of an ALJ recommendation related to the FERC ROE complaints. See Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints for more information.

2016 Compared with 2015

Earnings from our ownership interests in transmission affiliates increased $50.4 million during 2016, compared with 2015, primarily due to the increase in our ownership interest from 26.2% to approximately 60% as a result of the acquisition of Integrys on June 29, 2015. In addition, the lower earnings during 2015 were also driven by an ALJ initial decision issued in December 2015 related to the ATC ROE complaints, which was later affirmed by a FERC order in 2016.

CONSOLIDATED OTHER INCOME, NET

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
AFUDC – Equity	**$ 11.4**	$ 25.1	$ 20.1
Gain on repurchase of notes	**—**	23.6	—
Gain on asset sales	**1.9**	19.6	22.9
Other, net	**51.3**	12.5	15.9
Other income, net	**$ 64.6**	$ 80.8	$ 58.9

2017 Compared with 2016

Other income, net decreased $16.2 million during 2017, compared with 2016. This decrease was primarily driven by the $23.6 million gain recorded in February 2016 on the repurchase of a portion of Integrys's 2006 Junior Notes at a discount, the $19.6 million gain recorded in April 2016 from the sale of the chilled water generation and distribution assets of Wisvest, and lower AFUDC in 2017 largely due to the ReACT™ emission control technology project at Weston Unit 3 going into service during the fourth quarter of 2016. Partially offsetting these decreases were higher gains on investments held in our rabbi trust during 2017, compared with 2016. See Note 12, Long-Term Debt and Capital Lease Obligations, for more information on the note repurchase and Note 3, Dispositions, for information on our asset sales.

2016 Compared with 2015

Other income, net increased $21.9 million during 2016, compared with 2015. This increase was primarily driven by the repurchase of a portion of Integrys's 2006 Junior Notes at a discount in February 2016, as well as higher AFUDC in 2016 due to the inclusion of AFUDC from the Integrys companies post acquisition. Partially offsetting these increases was a $19.6 million gain recorded in April 2016 from the sale of the chilled water generation and distribution assets of Wisvest, compared with a $20.8 million gain from the sale of Minergy LLC and its remaining financial assets in June 2015, as well as excise tax credits recognized by ITF in 2015. ITF was sold in the first quarter of 2016.

CONSOLIDATED INTEREST EXPENSE

	Year Ended December 31		
(in millions)	**2017**	**2016**	**2015**
Interest expense	**$ 415.7**	$ 402.7	$ 331.4

2017 Compared with 2016

Interest expense increased $13.0 million during 2017, compared with 2016. The increase was primarily due to higher debt levels in 2017 to fund continued capital investments and lower capitalized interest during 2017, primarily as a result of the completion of the ReACT™ emission control project in 2016.

2016 Compared with 2015

Interest expense increased $71.3 million during 2016, compared with 2015. The increase was primarily driven by $68.5 million of interest expense from Integrys and its subsidiaries during the first six months of 2016, compared to no interest expense from these companies during the same period in 2015. Additionally, we issued $1.2 billion of long-term debt in June 2015 to finance a portion of the cash consideration for the acquisition of Integrys. This was offset, in part, by the repurchase of a portion of the 2006 Junior Notes in February 2016. These notes were replaced with lower-interest rate short-term debt.

CONSOLIDATED INCOME TAX EXPENSE

	Year Ended December 31		
	2017	**2016**	**2015**
Effective tax rate	**24.1%**	37.6%	40.4%

2017 Compared with 2016

Our effective tax rate was 24.1% in 2017 compared to 37.6% in 2016. This decrease was driven by a $206.7 million one-time net reduction in income tax expense related to the revaluation of our deferred taxes primarily on our non-utility energy infrastructure and corporate and other segments at December 31, 2017, as a result of the enactment of the Tax Legislation. Our effective tax rate in 2017 excluding the one-time net reduction in income tax expense due to revaluation of our deferred taxes was 37.2%. Preliminarily, we expect our 2018 annual effective tax rate to be between 15% and 16%, which includes an estimated 7% effective tax rate benefit due to the flow through of tax repairs in connection with the Wisconsin settlement. See Note 23, Regulatory Environment, for more information on the Wisconsin settlement. Excluding the impact of the tax repairs, the 2018 range would be between 22% and 23%. See Note 13, Income Taxes, for more information.

2016 Compared with 2015

Our effective tax rate was 37.6% in 2016 compared to 40.4% in 2015. This decrease was primarily related to a charge in 2015 to remeasure our state deferred income taxes as a result of the acquisition of Integrys.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during the years ended December 31:

(in millions)	2017	2016	2015	Change in 2017 Over 2016	Change in 2016 Over 2015
Cash provided by (used in):					
Operating activities	**$ 2,079.6**	$ 2,103.5	$ 1,293.6	$ (23.9)	$ 809.9
Investing activities	**(2,239.6)**	(1,270.1)	(2,517.5)	(969.5)	1,247.4
Financing activities	**161.4**	(845.7)	1,211.8	1,007.1	(2,057.5)

Operating Activities

2017 Compared with 2016

Net cash provided by operating activities decreased $23.9 million during 2017, compared with 2016, driven by:

- A $217.9 million decrease in cash resulting from higher payments for natural gas and fuel and purchased power in 2017, primarily due to higher commodity prices. The average per-unit cost of natural gas sold increased 13.6% during 2017, compared with 2016.
- A $91.8 million increase in contributions and payments to our pension and OPEB plans during 2017, compared with 2016.

- A $34.5 million net decrease in cash received from income taxes during 2017, compared with 2016. This decrease in cash was primarily due to the extension of bonus depreciation in December 2015, which resulted in the receipt of an income tax refund during 2016.
- A $26.5 million decrease in cash due to higher collateral requirements during 2017, compared with 2016, driven by a decrease in the fair value of our derivative instruments. See Note 15, Derivative Instruments, for more information.

These decreases in net cash provided by operating activities were partially offset by:

- A $158.7 million increase in cash from lower payments for operating and maintenance costs. During 2017, our payments related to transmission, electric and natural gas distribution, charitable projects, employee benefits, and electric generation decreased.
- A $129.2 million increase in cash related to higher overall collections from customers, primarily due to higher commodity prices during 2017, compared with 2016.
- A $49.6 million increase in cash distributions provided by ATC during 2017, compared with 2016.

2016 Compared with 2015

Net cash provided by operating activities increased $809.9 million during 2016, compared with 2015. This increase was driven by $466.6 million of net cash flows from the operating activities of Integrys during the first six months of 2016 since Integrys was acquired on June 29, 2015. See Note 2, Acquisitions, for more information.

The remaining $343.3 million increase in net cash provided by operating activities was driven by:

- A $377.9 million increase in cash resulting from lower payments for natural gas and fuel and purchased power in 2016, due to lower commodity prices and warmer weather during the 2016 heating season. The average per-unit cost of natural gas sold decreased 18.5% during 2016.
- A $94.2 million decrease in contributions and payments to our pension and OPEB plans during 2016, compared with 2015.
- A $44.1 million increase in cash due to lower collateral requirements during 2016, compared with 2015, driven by an increase in the fair value of our derivative instruments.
- A $29.2 million increase in cash received from income taxes, primarily due to a Wisconsin state income tax refund received in the fourth quarter of 2016.

These increases in net cash provided by operating activities were partially offset by a $210.8 million decrease in cash related to lower overall collections from customers. Collections from customers decreased primarily because of lower commodity prices and warmer weather during the 2016 heating season.

Investing Activities

2017 Compared with 2016

Net cash used in investing activities increased $969.5 million during 2017, compared with 2016, driven by:

- A $535.8 million increase in cash paid for capital expenditures during 2017, compared with 2016, which is discussed in more detail below.
- The acquisition of Bluewater during June 2017 for $226.0 million. See Note 2, Acquisitions, for more information.
- A $142.3 million decrease in the proceeds received from the sale of assets and businesses during 2017, compared with 2016. See Note 3, Dispositions, for more information.
- A $67.3 million increase in our capital contributions to ATC and ATC Holdco during 2017, compared with 2016, due to the continued investment in equipment and facilities by ATC to improve reliability and the restructuring of DATC's ownership. During the fourth quarter of 2017, ATC Holdco purchased ATC's ownership interest in DATC, which resulted in an increase in our capital contributions. In addition, the refunds paid by ATC in 2017 and ATC's lower earnings in 2016, as a result of the ATC ROE complaints filed with the FERC, also contributed to the year-over-year increase in our capital contributions. See Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints for more information on the ATC ROE complaints.

2016 Compared with 2015

Net cash used in investing activities decreased $1,247.4 million during 2016, compared with 2015, driven by:

- An investment of $1,329.9 million in June 2015 related to the acquisition of Integrys, which is net of cash acquired of $156.3 million. See Note 2, Acquisitions, for more information.

- A $137.4 million increase in the proceeds received from the sale of assets and businesses during 2016, compared with 2015.

These decreases in net cash used in investing activities were partially offset by:

- A $157.5 million increase in cash paid for capital expenditures during 2016, compared with 2015, which is discussed in more detail below.
- A $33.6 million increase in our capital contributions to ATC during 2016, compared with 2015, driven by both the continued investment in equipment and facilities by ATC to improve reliability and the increase in our ATC ownership interest as a result of the June 2015 Integrys acquisition.

Capital Expenditures

Capital expenditures by segment for the years ended December 31 were as follows:

Reportable Segment ***(in millions)***	**2017**	**2016**	**2015**	**Change in 2017 Over 2016**	**Change in 2016 Over 2015**
Wisconsin	**$ 1,152.3**	$ 910.9	$ 950.3	$ 241.4	$ (39.4)
Illinois	**545.2**	293.2	194.4	252.0	98.8
Other states	**74.5**	59.5	34.7	15.0	24.8
Non-utility energy infrastructure	**35.4**	62.3	53.4	(26.9)	8.9
Corporate and other	**152.1**	97.8	33.4	54.3	64.4
Total capital expenditures	**$ 1,959.5**	$ 1,423.7	$ 1,266.2	$ 535.8	$ 157.5

2017 Compared with 2016

The increase in cash paid for capital expenditures at the Wisconsin segment during 2017, compared with 2016, was driven by upgrades to our electric and natural gas distribution systems, including main replacement projects and an advanced metering infrastructure program, as well as WPS's SMRP and various projects at the OCPP. These increases in capital expenditures were partially offset by reduced construction activity at WPS related to the ReACT™ emission control technology project at Weston Unit 3, which was completed in 2016, and the combustion turbine project at the Fox Energy Center, which was completed in June 2017.

The increase in cash paid for capital expenditures at the Illinois segment during 2017, compared with 2016, was driven by increased construction activity related to PGL's SMP and natural gas storage field as well as a project to relocate one of PGL's service facilities.

The increase in cash paid for capital expenditures at the other states segment during 2017, compared with 2016, was driven by upgrades to MERC’s natural gas distribution systems and mains as well as the construction of an office building due to the relocation of MERC's headquarters during 2017.

The decrease in cash paid for capital expenditures at the non-utility energy infrastructure segment during 2017, compared with 2016, was driven by reduced construction activity for We Power's fuel flexibility project at the Oak Creek Expansion units, which was completed during December 2017.

The increase in cash paid for capital expenditures at the corporate and other segment during 2017, compared with 2016, was driven by a project to implement a new enterprise resource planning system and various other software projects.

See Capital Resources and Requirements – Capital Requirements – Capital Expenditures and Significant Capital Projects below for more information.

2016 Compared with 2015

The decrease in cash paid for capital expenditures at the Wisconsin segment during 2016, compared with 2015, was driven by the November 2015 completion of both WG's Western Gas Lateral project, which improved the reliability of WG's natural gas distribution network in the western part of Wisconsin, and WE's coal to natural gas conversion project at VAPP. Also contributing to the decrease were lower payments at WE for environmental compliance projects and electric distribution upgrades. The inclusion of WPS for all of 2016, as compared with only the last six months of 2015, substantially offset these lower capital expenditures. WPS's capital expenditures of $154.1 million during the first six months of 2016 related to the ReACT™ emission control technology project at Weston Unit 3, the combustion turbine project at the Fox Energy Center, and the SMRP.

The increase in cash paid for capital expenditures at the Illinois segment during 2016, compared with 2015, was due to the inclusion of PGL and NSG for all of 2016, compared with only the last six months of 2015. Capital expenditures at the Illinois segment were driven primarily by the SMP at PGL.

The increase in cash paid for capital expenditures at the other states segment during 2016, compared with 2015, was due to the inclusion of MERC and MGU for all of 2016, compared with only the last six months of 2015. MERC's and MGU's capital expenditures of $22.7 million during the first six months of 2016 primarily related to natural gas distribution systems and mains.

The increase in cash paid for capital expenditures at the corporate and other segment during 2016, compared with 2015, was driven by a project to implement a new enterprise resource planning system and an information technology project created to improve the billing, call center, and credit collection functions of the Integrys subsidiaries.

Financing Activities

2017 Compared with 2016

Net cash related to financing activities increased $1,007.1 million during 2017, compared with 2016, driven by:

- An $819.2 million net increase in cash due to $584.4 million of net borrowings of commercial paper during 2017, compared with $234.8 million of net repayments of commercial paper during 2016.
- A $151.5 million increase in cash related to lower long-term debt repayments during 2017, compared with 2016. In February 2016, we repurchased a portion of Integrys's 2006 Junior Notes at a discount.
- A $36.7 million increase in cash due to fewer shares of our common stock purchased during 2017, compared with 2016, to satisfy requirements of our stock-based compensation plans.
- A $35.0 million increase in cash due to the issuance of more long-term debt during 2017, compared with 2016.

These increases in net cash related to financing activities were partially offset by a $31.6 million increase in dividends paid on our common stock during 2017, compared with 2016. In January 2017, our Board of Directors increased our quarterly dividend by $0.025 per share effective with the first quarter of 2017 dividend payment.

2016 Compared with 2015

Net cash related to financing activities decreased $2,057.5 million during 2016, compared with 2015, driven by:

- A $1,526.4 million net decrease in cash due to a $1,750.0 million decrease in the issuance of long-term debt during 2016, partially offset by $223.6 million of lower repayments of long-term debt during 2016. We issued $1,200.0 million of long-term debt during 2015 in connection with the acquisition of Integrys.
- A $397.8 million net decrease in cash due to $234.8 million of net repayments of commercial paper during 2016, compared with $163.0 million of net borrowings of commercial paper during 2015.
- A $169.5 million increase in dividends paid on common stock during 2016, compared with 2015, due to the issuance of 90.2 million shares of our common stock in June 2015 as a result of the Integrys acquisition and increases to our quarterly dividend rate. See Note 2, Acquisitions, for more information.
- A $33.3 million decrease in cash due to more shares of our common stock purchased during 2016, compared with 2015, to satisfy requirements of our stock-based compensation plans.

These decreases in net cash related to financing activities were partially offset by a $52.7 million increase in cash due to the redemption of all of WPS's preferred stock during 2015.

Significant Financing Activities

For more information on our financing activities, see Note 11, Short-Term Debt and Lines of Credit, and Note 12, Long-Term Debt and Capital Lease Obligations.

CAPITAL RESOURCES AND REQUIREMENTS

Capital Resources

Liquidity

We anticipate meeting our capital requirements for our existing operations through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities, depending on market conditions and other factors.

We currently have access to the capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We currently believe that we have adequate capacity to fund our operations for the foreseeable future through our existing borrowing arrangements, access to capital markets, and internally generated cash.

WEC Energy Group, WE, WG, WPS, and PGL maintain bank back-up credit facilities, which provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes. We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. See Note 11, Short-Term Debt and Lines of Credit, for more information about these credit facilities.

The following table shows our capitalization structure as of December 31, 2017 and 2016, as well as an adjusted capitalization structure that we believe is consistent with how a majority of the rating agencies currently view our 2007 Junior Notes:

	2017		**2016**	
(in millions)	**Actual**	**Adjusted**	**Actual**	**Adjusted**
Common equity	**$ 9,461.4**	**$ 9,711.4**	$ 8,929.8	$ 9,179.8
Preferred stock of subsidiary	**30.4**	**30.4**	30.4	30.4
Long-term debt (including current portion)	**9,588.7**	**9,338.7**	9,315.4	9,065.4
Short-term debt	**1,444.6**	**1,444.6**	860.2	860.2
Total capitalization	**$ 20,525.1**	**$ 20,525.1**	$ 19,135.8	$ 19,135.8
Total debt	**$ 11,033.3**	**$ 10,783.3**	$ 10,175.6	$ 9,925.6
Ratio of debt to total capitalization	**53.8%**	**52.5%**	53.2%	51.9%

Included in long-term debt on our balance sheets as of December 31, 2017 and 2016, is $500.0 million principal amount of 2007 Junior Notes. The adjusted presentation attributes $250.0 million of the 2007 Junior Notes to common equity and $250.0 million to long-term debt.

The adjusted presentation of our consolidated capitalization structure is included as a complement to our capitalization structure presented in accordance with GAAP. Management evaluates and manages our capitalization structure, including our total debt to total capitalization ratio, using the GAAP calculation as adjusted by the rating agency treatment of the 2007 Junior Notes. Therefore, we believe the non-GAAP adjusted presentation reflecting this treatment is useful and relevant to investors in understanding how management and the rating agencies evaluate our capitalization structure.

For a summary of the interest rate, maturity, and amount outstanding of each series of our long-term debt on a consolidated basis, see our capitalization statements.

As described in Note 9, Common Equity, certain restrictions exist on the ability of our subsidiaries to transfer funds to us. We do not expect these restrictions to have any material effect on our operations or ability to meet our cash obligations.

At December 31, 2017, we were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 11, Short-Term Debt and Lines of Credit, for more information about our credit facilities and other short-term credit agreements. See Note 12, Long-Term Debt and Capital Lease Obligations, for more information about our long-term debt.

Working Capital

As of December 31, 2017, our current liabilities exceeded our current assets by $1,655.8 million. We do not expect this to have any impact on our liquidity since we believe we have adequate back-up lines of credit in place for our ongoing operations. We also believe that we can access the capital markets to finance our construction programs and to refinance current maturities of long-term debt, if necessary.

Credit Rating Risk

We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. However, we have certain agreements in the form of commodity contracts and employee benefit plans that could require collateral or a termination payment in the event of a credit rating change to below BBB- at S&P Global Ratings and/or Baa3 at Moody's Investors Service. We also have other commodity contracts that, in the event of a credit rating downgrade, could result in a reduction of our unsecured credit granted by counterparties.

In addition, access to capital markets at a reasonable cost is determined in large part by credit quality. Any credit ratings downgrade could impact our ability to access capital markets.

In January 2018, Moody's downgraded the rating outlook for WG to negative from stable as a result of the new Tax Legislation. We do not believe the change in rating outlook will have a material impact on our ability to access capital markets.

In July 2017, Moody's downgraded the ratings of WE (senior unsecured), WPS (senior unsecured), WG (senior unsecured), and ERGSS (senior secured) to A2 from A1. Moody's affirmed the commercial paper ratings of WE (P-1), WPS (P-1), and WG (P-1). Moody's also affirmed the ratings of WEC Energy Group (senior unsecured, A3), WECC (senior unsecured, A3), and Integrys (senior unsecured, A3), but changed the rating outlook for these companies to negative from stable. We do not believe the changes in ratings and rating outlook will have a material impact on our ability to access capital markets.

Subject to other factors affecting the credit markets as a whole, we believe our current ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agency only. An explanation of the significance of these ratings may be obtained from the rating agency. Such ratings are not a recommendation to buy, sell, or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency.

If we are unable to successfully take actions to manage any adverse impacts of the Tax Legislation, or if additional interpretations, regulations, amendments or technical corrections exacerbate the adverse impacts of the Tax Legislation, the legislation could result in credit rating agencies placing our or our subsidiaries' credit ratings on negative outlook or downgrading our or our subsidiaries' credit ratings. Any such actions by credit rating agencies may make it more difficult and costly for us and our subsidiaries to issue future debt securities and certain other types of financing and could increase borrowing costs under our and our subsidiaries' credit facilities.

Capital Requirements

Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2017:

	Payments Due by Period [1]				
(in millions)	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Long-term debt obligations [2]	$ 18,025.9	$ 1,238.0	$ 1,801.1	$ 1,070.5	$ 13,916.3
Capital lease obligations [3]	71.4	14.7	31.9	24.8	—
Operating lease obligations [4]	115.1	9.5	16.8	14.7	74.1
Energy and transportation purchase obligations [5]	11,640.9	1,084.2	1,691.4	1,369.7	7,495.6
Purchase orders [6]	1,168.6	851.3	137.7	77.7	101.9
Pension and OPEB funding obligations [7]	49.0	13.1	35.9	—	—
Total contractual obligations	$ 31,070.9	$ 3,210.8	$ 3,714.8	$ 2,557.4	$ 21,587.9

(1) The amounts included in the table are calculated using current market prices, forward curves, and other estimates.

(2) Principal and interest payments on long-term debt (excluding capital lease obligations). The interest due on our variable rate debt is based on the interest rates that were in effect on December 31, 2017.

(3) Capital lease obligations for power purchase commitments. This amount does not include We Power leases to WE which are eliminated upon consolidation.

(4) Operating lease obligations for power purchase commitments and rail car leases.

(5) Energy and transportation purchase obligations under various contracts for the procurement of fuel, power, gas supply, and associated transportation related to utility operations.

(6) Purchase obligations related to normal business operations, information technology, and other services.

(7) Obligations for pension and OPEB plans cannot reasonably be estimated beyond 2020.

The table above does not include liabilities related to the accounting treatment for uncertainty in income taxes because we are not able to make a reasonably reliable estimate as to the amount and period of related future payments at this time. For additional information regarding these liabilities, refer to Note 13, Income Taxes.

The table above also does not reflect estimated future payments related to the manufactured gas plant remediation liability of $617.2 million at December 31, 2017, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 21, Commitments and Contingencies, for more information about environmental liabilities.

AROs in the amount of $573.7 million are not included in the above table. Settlement of these liabilities cannot be determined with certainty, but we believe the majority of these liabilities will be settled in more than five years.

Obligations for utility operations have historically been included as part of the rate-making process and therefore are generally recoverable from customers.

Capital Expenditures and Significant Capital Projects

We have several capital projects that will require significant capital expenditures over the next three years and beyond. All projected capital requirements are subject to periodic review and may vary significantly from estimates, depending on a number of factors. These factors include environmental requirements, regulatory restraints and requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, and economic trends. Our estimated capital expenditures and acquisitions for the next three years are as follows:

(in millions)	2018	2019	2020
Wisconsin	$ 1,430.1	$ 1,152.0	$ 1,850.2
Illinois	633.8	629.2	676.5
Other states	99.6	116.1	110.6
Non-utility energy infrastructure	280.8	60.5	51.9
Corporate and other	20.7	13.2	0.8
Total	$ 2,465.0	$ 1,971.0	$ 2,690.0

WPS is continuing work on the SMRP. This project includes modernizing parts of its electric distribution system, including burying or upgrading lines. The project focuses on constructing facilities to improve the reliability of electric service WPS provides to its customers. WPS expects to invest approximately $250 million between 2018 and 2022 on this project. WE, WPS, and WG will also continue to upgrade their electric and natural gas distribution systems to enhance reliability. These upgrades include the advanced metering infrastructure (AMI) program. AMI is an integrated system of smart meters, communication networks and data management systems that enable two-way communication between utilities and customers.

As part of our commitment to invest in zero-carbon generation, we plan to invest in utility scale solar of up to 350 MW within our Wisconsin segment. Solar generation technology has greatly improved, has become more cost-effective, and it complements our summer demand curve.

In connection with the formation of UMERC, we entered into an agreement with Tilden under which it will purchase electric power from UMERC for 20 years, contingent upon UMERC's construction of approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan. The new generation is expected to begin commercial operation in 2019. The estimated cost of this project is approximately $266 million ($277 million with AFUDC). See Note 23, Regulatory Environment, for more information about UMERC and this new generation.

PGL is continuing work on the SMP, a project under which PGL is replacing approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure. PGL currently recovers these costs through a surcharge on customer bills pursuant to an ICC approved QIP rider, which is in effect through 2023. PGL's projected average annual investment through 2020 is between $280 million and $300 million. See Note 23, Regulatory Environment, for more information on the SMP.

We expect to provide capital contributions to ATC and ATC Holdco (not included in the above table) of approximately $200 million from 2018 through 2020.

Common Stock Matters

For information related to our common stock matters, see Note 9, Common Equity.

On January 18, 2018, our Board of Directors increased our quarterly dividend to $0.5525 per share effective with the first quarter of 2018 dividend payment, which equates to an annual dividend of $2.21 per share. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

Investments in Outside Trusts

We use outside trusts to fund our pension and certain OPEB obligations. These trusts had investments of approximately $3.8 billion as of December 31, 2017. These trusts hold investments that are subject to the volatility of the stock market and interest rates. We contributed $120.5 million, $28.7 million, and $121.0 million to our pension and OPEB plans in 2017, 2016, and 2015, respectively. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note 17, Employee Benefits.

Off-Balance Sheet Arrangements

We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit that support construction projects, commodity contracts, and other payment obligations. We believe that these agreements do not have, and are not reasonably likely to have, a current or future material effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources. For additional information, see Note 11, Short-Term Debt and Lines of Credit, Note 16, Guarantees, and Note 20, Variable Interest Entities.

FACTORS AFFECTING RESULTS, LIQUIDITY, AND CAPITAL RESOURCES

MARKET RISKS AND OTHER SIGNIFICANT RISKS

We are exposed to market and other significant risks as a result of the nature of our businesses and the environments in which those businesses operate. These risks, described in further detail below, include but are not limited to:

Regulatory Recovery

Our utilities account for their regulated operations in accordance with accounting guidance under the Regulated Operations Topic of the FASB ASC. Our rates are determined by various regulatory commissions.

Regulated entities are allowed to defer certain costs that would otherwise be charged to expense if the regulated entity believes the recovery of the costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by our regulators. Recovery of the deferred costs in future rates is subject to the review and approval by our regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of the deferred costs, including those referenced below, is not approved by our regulators, the costs would be charged to income in the current period. In general, our regulatory assets are recovered over a period of between one to six years. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. We record these items as regulatory liabilities. As of December 31, 2017, our regulatory assets were $2,840.4 million, and our regulatory liabilities were $3,760.4 million.

Due to the Tax Legislation signed into law in December 2017, our regulated utilities remeasured their deferred taxes and recorded an estimated tax benefit of $2,450 million. This tax benefit will be returned to ratepayers through future refunds, bill credits, riders, or reductions to other regulatory assets. See Note 13, Income Taxes, and Note 23, Regulatory Environment, for more information.

We expect to request or have requested recovery of the costs related to the following projects discussed in recent or pending rate proceedings, orders, and investigations involving our utilities:

- In June 2016, the PSCW approved the deferral of costs related to WPS's ReACT™ project above the originally authorized $275.0 million level through 2017. The total cost of the ReACT™ project, excluding $51 million of AFUDC, is currently estimated to be $342 million. In September 2017, the PSCW approved an extension of this deferral through 2019 as part of a settlement agreement. See Note 23, Regulatory Environment, for more information. WPS will be required to obtain a separate approval for collection of these deferred costs in a future rate case.
- Prior to its acquisition, Integrys initiated an information technology project with the goal of improving the customer experience at its subsidiaries. Specifically, the project is expected to provide functional and technological benefits to the billing, call center, and credit collection functions. As of December 31, 2017, we had not received any significant disallowances of the costs incurred for this project. We will be required to obtain approval for the recovery of additional costs incurred through the completion of this long-term project.
- In January 2014, the ICC approved PGL's use of the QIP rider as a recovery mechanism for costs incurred related to investments in QIP. This rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2017, PGL filed its 2016 reconciliation with the ICC, which, along with the 2015 reconciliation, is still pending. In

2018, PGL agreed to a settlement of the 2014 reconciliation, which includes a rate base reduction of $5.4 million and a $4.7 million refund to ratepayers. As of December 31, 2017, there can be no assurance that all costs incurred under the QIP rider during the open reconciliation years will be deemed recoverable by the ICC.

See Note 23, Regulatory Environment, for more information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

Commodity Costs

In the normal course of providing energy, we are subject to market fluctuations in the costs of coal, natural gas, purchased power, and fuel oil used in the delivery of coal. We manage our fuel and natural gas supply costs through a portfolio of short and long-term procurement contracts with various suppliers for the purchase of coal, natural gas, and fuel oil. In addition, we manage the risk of price volatility through natural gas and electric hedging programs.

Embedded within our utilities' rates are amounts to recover fuel, natural gas, and purchased power costs. Our utilities have recovery mechanisms in place that allow them to recover or refund all or a portion of the changes in prudently incurred fuel, natural gas, and purchased power costs from rate case-approved amounts.

Higher commodity costs can increase our working capital requirements, result in higher gross receipts taxes, and lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution. Higher commodity costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. See Note 1(d), Revenues and Customer Receivables, for more information on riders and other mechanisms that allow for cost recovery or refund of uncollectible expense.

Weather

Our utilities' rates are based upon estimated normal temperatures. Our electric utility margins are unfavorably sensitive to below normal temperatures during the summer cooling season and, to some extent, to above normal temperatures during the winter heating season. Our natural gas utility margins are unfavorably sensitive to above normal temperatures during the winter heating season. PGL, NSG, and MERC have decoupling mechanisms in place that help reduce the impacts of weather. Decoupling mechanisms differ by state and allow utilities to recover or refund certain differences between actual and authorized margins. A summary of actual weather information in our utilities' service territories during 2017, 2016, and 2015, as measured by degree days, may be found in Results of Operations.

Interest Rates

We are exposed to interest rate risk resulting from our short-term and long-term borrowings and projected near-term debt financing needs. We manage exposure to interest rate risk by limiting the amount of our variable rate obligations and continually monitoring the effects of market changes on interest rates. When it is advantageous to do so, we enter into long-term fixed rate debt. We may also enter into derivative financial instruments, such as swaps, to mitigate interest rate exposure.

Based on the variable rate debt outstanding at December 31, 2017, and December 31, 2016, a hypothetical increase in market interest rates of one percentage point would have increased annual interest expense by $20.6 million and $9.8 million in 2017 and 2016, respectively. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Marketable Securities Return

We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. We believe that the financial risks associated with investment returns would be partially mitigated through future rate actions by our various utility regulators.

The fair value of our trust fund assets and expected long-term returns were approximately:

(in millions)	**As of December 31, 2017**	**Expected Return on Assets in 2018**
Pension trust funds	$ 2,966.8	7.12%
OPEB trust funds	$ 841.5	7.25%

Fiduciary oversight of the pension and OPEB trust fund investments is the responsibility of an Investment Trust Policy Committee. The Committee works with external actuaries and investment consultants on an ongoing basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target asset allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. The targeted asset allocations are intended to reduce risk, provide long-term financial stability for the plans, and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments. Investment strategies utilize a wide diversification of asset types and qualified external investment managers.

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing actual historical returns and calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the funds.

Economic Conditions

We have electric and natural gas utility operations that serve customers in Wisconsin, Illinois, Michigan, and Minnesota. As such, we are exposed to market risks in the regional Midwest economy. In addition, any economic downturn or disruption of national or international markets could adversely affect the financial condition of our customers and demand for their products, which could affect their demand for our products.

Inflation

We continue to monitor the impact of inflation, especially with respect to the costs of medical plans, fuel, transmission access, construction costs, and regulatory and environmental compliance in order to minimize its effects in future years through pricing strategies, productivity improvements, and cost reductions. We do not believe the impact of general inflation will have a material impact on our future results of operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report.

INDUSTRY RESTRUCTURING

Electric Utility Industry

The regulated energy industry continues to experience significant changes. The FERC continues to support large RTOs, which affects the structure of the wholesale market. To this end, MISO implemented the MISO Energy Markets, including the use of LMP to value electric transmission congestion and losses. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us. It is uncertain when, if at all, retail choice might be implemented in Wisconsin. However, Michigan has adopted a limited retail choice program.

Restructuring in Wisconsin

Electric utility revenues in Wisconsin are regulated by the PSCW. The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date.

Restructuring in Michigan

Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. As a result, some of our small retail customers have switched to an alternative electric supplier. At December 31, 2017, Michigan law limited customer choice to 10% of an electric utility's Michigan retail load, but this cap could potentially be reduced in future years due to the December 2016 passage of Michigan Act 341. Based on current law, our iron ore mine customer, Tilden, is exempt from the 10% cap. In addition, certain load increases by facilities already using an alternative electric supplier can still be serviced by their alternative electric supplier, when various conditions exist, even if the cap has already been met. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

Natural Gas Utility Industry

We offer natural gas transportation services to our customers that elect to purchase natural gas from an alternative retail natural gas supplier. Since these transportation customers continue to use our distribution systems to transport natural gas to their facilities, we earn distribution revenues from them. As such, there is little impact on our net income from customers purchasing natural gas from an alternative retail natural gas supplier as natural gas costs are passed through to customers in rates on a one-for-one basis.

Restructuring in Wisconsin

The PSCW previously instituted generic proceedings to consider how its regulation of natural gas distribution utilities should change to reflect a competitive environment in the natural gas industry. To date, the PSCW has made a policy decision to provide customer classes with competitive market choices the option to choose an alternative retail natural gas supplier. The PSCW has also adopted standards for transactions between a utility and its natural gas marketing affiliates. All of our Wisconsin customer classes have competitive market choices and, therefore, can purchase natural gas directly from either an alternative retail natural gas supplier or their local natural gas utility. Currently, we are unable to predict the impact of potential future industry restructuring on our results of operations or financial position.

Restructuring in Illinois

Since 2002, PGL and NSG have provided their customers with the option to choose an alternative retail natural gas supplier. We are not required by the ICC or state law to make this option available to customers, but since this option is currently provided to our Illinois customers, we would need ICC approval to eliminate it.

Restructuring in Minnesota

MERC has provided its commercial and industrial customers with the option to choose an alternative retail natural gas supplier since 2006. We are not required by the MPUC or state law to make this option available to customers, but since this option is currently provided to our Minnesota commercial and industrial customers, we would need MPUC approval to eliminate it.

Restructuring in Michigan

The option to choose an alternative retail natural gas supplier has been provided to UMERC’s customers (formerly WPS’s Michigan customers) since the late 1990s and MGU's customers since 2005. We are not required by the MPSC or state law to make this option available to customers, but since this option is currently provided to our Michigan customers, we would need MPSC approval to eliminate it.

ENVIRONMENTAL MATTERS

See Note 21, Commitments and Contingencies, for a discussion of certain environmental matters affecting us, including rules and regulations relating to air quality, water quality, land quality, and climate change.

OTHER MATTERS

American Transmission Company Allowed Return on Equity Complaints

In November 2013, a group of MISO industrial customer organizations filed a complaint with the FERC requesting to reduce the base ROE used by MISO transmission owners, including ATC, from 12.2% to 9.15%. In October 2014, the FERC issued an order to hear the complaint on ROE and set a refund effective date retroactive to November 2013. In December 2015, the ALJ issued an initial decision recommending that ATC and all other MISO transmission owners be authorized to collect a base ROE of 10.32%, as well as the 0.5% incentive adder approved by the FERC in January 2015 for MISO transmission owners. The incentive adder only applies to revenues collected after January 6, 2015. In September 2016, the FERC issued a final order related to this complaint affirming the use of the ROE stated in the ALJ's initial decision, effective as of the order date, on a going-forward basis. The order also required ATC to provide refunds, with interest, for the 15-month refund period from November 12, 2013, through February 11, 2015. The refunds ATC provided to WE and WPS for transmission costs paid during the refund period reduced the regulatory assets recorded under the PSCW-approved escrow accounting for transmission expense and resulted in a net regulatory liability for WPS. See Note 18, Investment in Transmission Affiliates, for more information.

In February 2015, a second complaint was filed with the FERC requesting a reduction in the base ROE used by MISO transmission owners, including ATC, to 8.67%, with a refund effective date retroactive to February 12, 2015. In June 2016, the ALJ issued an initial decision recommending that ATC and all other MISO transmission owners be authorized to collect a base ROE of 9.7%, as well as the 0.5% incentive adder approved for MISO transmission owners. The ALJ's initial decision is not binding on the FERC and applies to revenues collected from February 12, 2015, through May 11, 2016. We are uncertain when a FERC order related to this matter will be issued.

The MISO transmission owners have filed various appeals related to several of the FERC orders with the D.C. Circuit Court of Appeals as well as requests for rehearing.

The decrease in ATC's ROE resulting from the FERC's final order issued in September 2016 will continue to have a negative impact on our equity earnings and distributions from ATC.

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the Tax Legislation was signed into law. See Note 13, Income Taxes, and Note 23, Regulatory Environment, for more information regarding its impact on us.

Bonus Depreciation Provisions

Bonus depreciation is an additional amount of first-year tax deductible depreciation that is awarded above what would normally be available. Based on the Protecting Americans from Tax Hikes Act of 2015, a 50% bonus depreciation deduction was available for assets placed in service during 2017. The increase in our federal tax depreciation from this deduction significantly reduced our 2017 federal income tax payment.

On December 22, 2017, the Tax Legislation was signed into law. This legislation modified the bonus depreciation deduction available for public utility property subject to rate-making by a government entity or public utility commission. See Note 13, Income Taxes, for more information.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges, and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment may also have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective, or complex judgments.

Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of July 1, 2017. No impairments were recorded as a result of these tests. For our Bluewater reporting unit, we assumed fair value equaled carrying value since Bluewater was acquired on June 30, 2017. For all of our other reporting units that carried a goodwill balance, the fair values calculated in step one of the test were greater than their carrying values. The fair values for these reporting units were calculated using a combination of the income approach and the market approach.

For the income approach, we used internal forecasts to project cash flows. Any forecast contains a degree of uncertainty, and changes in these cash flows could significantly increase or decrease the fair value of a reporting unit. Since all of our reporting units are regulated, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair values of our reporting units to decrease.

Key assumptions used in the income approach included ROEs, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The discount rate is based on the weighted-average cost of capital for each reporting unit, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE for each utility is driven by its current allowed ROE. The terminal growth rate is based primarily on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

For the market approach, we used an equal weighting of the guideline public company method and the guideline merged and acquired company method. The guideline public company method uses financial metrics from similar publicly traded companies to determine fair value. The guideline merged and acquired company method calculates fair value by analyzing the actual prices paid for recent mergers and acquisitions in the industry. We applied multiples derived from these two methods to the appropriate operating metrics for our reporting units to determine fair value.

The underlying assumptions and estimates used in the impairment tests were made as of a point in time. Subsequent changes in these assumptions and estimates could change the results of the tests.

For all of our reporting units other than Bluewater, fair value exceeded carrying value by over 50%. For Bluewater, we assumed fair value equaled carrying value since we acquired Bluewater on June 30, 2017. Based on these results, our reporting units are not at risk of failing step one of the goodwill impairment test.

Our reporting units had the following goodwill balances at July 1, 2017:

(in millions, except percentages)	Goodwill	Percentage of Total Goodwill
Wisconsin	$ 2,104.3	68.9%
Illinois	758.7	24.9%
Other states	183.2	6.0%
Bluewater	7.3	0.2%
Total goodwill	$ 3,053.5	100.0%

See Note 8, Goodwill, for more information.

Long-Lived Assets

We periodically assess the recoverability of certain long-lived assets when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include certain assets within regulated operations that may not be fully recovered from our customers as a result of regulatory decisions that will be made in the future, and assets within nonregulated operations that are proposed to be sold or are currently generating operating losses.

We have evaluated future plans for our older fossil fuel generating units and have announced our plans for the retirement of certain older and less-efficient generating units. When it becomes probable that a generating unit will be retired before the end of its useful life, we assess whether the generating unit meets the criteria for abandonment accounting. Generating units that are considered probable of abandonment are expected to cease operations in the near term, significantly before the end of their original estimated useful lives. As a result, the remaining net book value of these assets can be significant. If a generating unit meets applicable criteria to be considered probable of abandonment, we assess the likelihood of recovery of the remaining carrying value of that generating unit at the end of each reporting period. If it becomes probable that regulators will disallow full recovery as well as a return on the remaining net book value of the abandoned generating unit, an impairment charge may be required. An impairment charge would be recorded if the remaining carrying value of the abandoned generating unit is greater than the present value of the amount expected to be recovered from ratepayers.

We concluded that the Pleasant Prairie power plant, PIPP, the Pulliam power plant, and the jointly-owned Edgewater 4 generating unit meet the criteria to be considered probable of abandonment as of December 31, 2017. We plan to ask for full cost recovery of and a full return on the remaining book value of the generating units and have concluded that no impairment was required related to these assets as of December 31, 2017.

See Note 5, Property, Plant, and Equipment, for more information on the units to be retired.

Pension and Other Postretirement Employee Benefits

The costs of providing non-contributory defined pension benefits and OPEB, described in Note 17, Employee Benefits, are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension and OPEB costs are impacted by actual employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans, and earnings on plan assets. Pension and OPEB costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, mortality and discount rates, and expected health care cost trends. Changes made to the plan provisions may also impact current and future pension and OPEB costs.

Pension and OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and fixed income market returns, as well as changes in general interest rates, may result in increased or decreased benefit costs in future periods. We believe that such changes in costs would be recovered or refunded at our utilities through the rate-making process.

The following table shows how a given change in certain actuarial assumptions would impact the projected benefit obligation and the reported net periodic pension cost. Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption ***(in millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Projected Benefit Obligation**	**Impact on 2017 Pension Cost**
Discount rate	(0.5)	$ 211.3	$ 18.3
Discount rate	0.5	(183.6)	(10.3)
Rate of return on plan assets	(0.5)	N/A	13.6
Rate of return on plan assets	0.5	N/A	(13.6)

The following table shows how a given change in certain actuarial assumptions would impact the accumulated OPEB obligation and the reported net periodic OPEB cost. Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption ***(in millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Postretirement Benefit Obligation**	**Impact on 2017 Postretirement Benefit Cost**
Discount rate	(0.5)	$ 56.2	$ 2.6
Discount rate	0.5	(49.3)	(1.3)
Health care cost trend rate	(0.5)	(31.9)	(3.3)
Health care cost trend rate	0.5	37.1	3.8
Rate of return on plan assets	(0.5)	N/A	3.8
Rate of return on plan assets	0.5	N/A	(3.8)

The discount rates are selected based on hypothetical bond portfolios consisting of noncallable (or callable with make-whole provisions), noncollateralized, high-quality corporate bonds across the full maturity spectrum. The bonds are generally rated "Aa" with a minimum amount outstanding of $50.0 million. From the hypothetical bond portfolios, a single rate is determined that equates the market value of the bonds purchased to the discounted value of the plans' expected future benefit payments.

We establish our expected return on assets based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. The assumed long-term rate of return on pension plan assets was 7.11%, 7.12%, and 7.37%, in 2017, 2016, and 2015, respectively. The actual rate of return on pension plan assets, net of fees, was 13.74%, 7.75%, and (3.85)%, in 2017, 2016, and 2015, respectively.

In selecting assumed health care cost trend rates, past performance and forecasts of health care costs are considered. For more information on health care cost trend rates and a table showing future payments that we expect to make for our pension and OPEB, see Note 17, Employee Benefits.

Regulatory Accounting

Our utility operations follow the guidance under the Regulated Operations Topic of the FASB ASC. Our financial statements reflect the effects of the rate-making principles followed by the various jurisdictions regulating us. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by our regulators.

Future recovery of regulatory assets is not assured and is generally subject to review by regulators in rate proceedings for matters such as prudence and reasonableness. Once approved, the regulatory assets and liabilities are amortized into earnings over the rate recovery period. If recovery or refund of costs is not approved or is no longer considered probable, these regulatory assets or liabilities are recognized in current period earnings. Management regularly assesses whether these regulatory assets and liabilities are probable of future recovery or refund by considering factors such as changes in the regulatory environment, earnings from our electric and natural gas utility operations, and the status of any pending or potential deregulation legislation.

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our utility operations no longer met the criteria for application. Our regulatory assets and liabilities would be written off to income as an unusual or infrequently occurring item in the period in which discontinuation occurred. As of December 31, 2017, we had $2,840.4 million in regulatory assets and $3,760.4 million in regulatory liabilities. See Note 4, Regulatory Assets and Liabilities, for more information.

Unbilled Revenues

We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses, and applicable customer rates. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total utility operating revenues during 2017 of approximately $7.6 billion included accrued utility revenues of $538.1 million as of December 31, 2017.

Income Tax Expense

We are required to estimate income taxes for each of the jurisdictions in which we operate as part of the process of preparing financial statements. This process involves estimating current income tax liabilities together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for income tax and accounting purposes. These differences result in deferred income tax assets and liabilities, which are included within our balance sheets. We also assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that realization is not likely, we establish a valuation allowance, which is offset by an adjustment to the provision for income taxes in the income statements.

Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals requires that judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" recognition threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of our tax returns.

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(o), Income Taxes, and Note 13, Income Taxes, for a discussion of accounting for income taxes.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks, as well as Note 1(p), Fair Value Measurements, Note 1(q), Derivative Instruments, and Note 16, Guarantees, for information concerning potential market risks to which we are exposed.

WEC ENERGY GROUP, INC.
CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions, except per share amounts)*	2017	2016	2015
Operating revenues	**$ 7,648.5**	$ 7,472.3	$ 5,926.1
Operating expenses			
Cost of sales	**2,822.8**	2,647.4	2,240.1
Other operation and maintenance	**2,047.0**	2,185.5	1,709.3
Depreciation and amortization	**798.6**	762.6	561.8
Property and revenue taxes	**194.9**	194.7	164.4
Total operating expenses	**5,863.3**	5,790.2	4,675.6
Operating income	**1,785.2**	1,682.1	1,250.5
Equity in earnings of transmission affiliates	**154.3**	146.5	96.1
Other income, net	**64.6**	80.8	58.9
Interest expense	**415.7**	402.7	331.4
Other expense	**(196.8)**	(175.4)	(176.4)
Income before income taxes	**1,588.4**	1,506.7	1,074.1
Income tax expense	**383.5**	566.5	433.8
Net income	**1,204.9**	940.2	640.3
Preferred stock dividends of subsidiary	**1.2**	1.2	1.8
Net income attributed to common shareholders	**$ 1,203.7**	$ 939.0	$ 638.5
Earnings per share			
Basic	**$ 3.81**	$ 2.98	$ 2.36
Diluted	**$ 3.79**	$ 2.96	$ 2.34
Weighted average common shares outstanding			
Basic	**315.6**	315.6	271.1
Diluted	**317.2**	316.9	272.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WEC ENERGY GROUP, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2017	2016	2015
Net income	**$ 1,204.9**	$ 940.2	$ 640.3
Other comprehensive (loss) income, net of tax			
Derivatives accounted for as cash flow hedges			
Gains on settlement, net of tax of $7.6	**—**	—	11.4
Reclassification of gains to net income, net of tax	**(1.3)**	(1.3)	(0.8)
Cash flow hedges, net	**(1.3)**	(1.3)	10.6
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax of $0.6, $0.1, and $(4.2), respectively	**0.9**	(0.8)	(6.3)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.4**	0.4	—
Defined benefit plans, net	**1.3**	(0.4)	(6.3)
Other comprehensive (loss) income, net of tax	**—**	(1.7)	4.3
Comprehensive income	**1,204.9**	938.5	644.6
Preferred stock dividends of subsidiary	**1.2**	1.2	1.8
Comprehensive income attributed to common shareholders	**$ 1,203.7**	$ 937.3	$ 642.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WEC ENERGY GROUP, INC.
CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share amounts)*	2017	2016
Assets		
Current assets		
Cash and cash equivalents	**$ 38.9**	$ 37.5
Accounts receivable and unbilled revenues, net of reserves of $143.2 and $108.0, respectively	**1,350.7**	1,241.7
Materials, supplies, and inventories	**539.0**	587.6
Prepayments	**210.0**	204.4
Other	**74.9**	97.5
Current assets	**2,213.5**	2,168.7
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $8,618.5 and $8,214.6, respectively	**21,347.0**	19,915.5
Regulatory assets	**2,803.2**	3,087.9
Equity investment in transmission affiliates	**1,553.4**	1,443.9
Goodwill	**3,053.5**	3,046.2
Other	**619.9**	461.0
Long-term assets	**29,377.0**	27,954.5
Total assets	**$ 31,590.5**	$ 30,123.2
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 1,444.6**	$ 860.2
Current portion of long-term debt	**842.1**	157.2
Accounts payable	**859.9**	861.5
Accrued payroll and benefits	**169.1**	163.8
Other	**553.6**	388.9
Current liabilities	**3,869.3**	2,431.6
Long-term liabilities		
Long-term debt	**8,746.6**	9,158.2
Deferred income taxes	**2,999.8**	5,146.6
Deferred revenue, net	**543.3**	566.2
Regulatory liabilities	**3,718.6**	1,563.8
Environmental remediation liabilities	**617.4**	633.6
Pension and OPEB obligations	**397.4**	498.6
Other	**1,206.3**	1,164.4
Long-term liabilities	**18,229.4**	18,731.4
Commitments and contingencies (Note 21)		
Common shareholders' equity		
Common stock – $0.01 par value; 325,000,000 shares authorized; 315,574,624 and 315,614,941 shares outstanding, respectively	**3.2**	3.2
Additional paid in capital	**4,278.5**	4,309.8
Retained earnings	**5,176.8**	4,613.9
Accumulated other comprehensive income	**2.9**	2.9
Common shareholders' equity	**9,461.4**	8,929.8
Preferred stock of subsidiary	**30.4**	30.4
Total liabilities and equity	**$ 31,590.5**	$ 30,123.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WEC ENERGY GROUP, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2017	2016	2015
Operating activities			
Net income	**$ 1,204.9**	$ 940.2	$ 640.3
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**798.6**	762.6	583.5
Deferred income taxes and investment tax credits, net	**271.7**	493.8	418.7
Contributions and payments related to pension and OPEB plans	**(120.5)**	(28.7)	(121.0)
Equity income in transmission affiliates, net of distributions	**(4.8)**	(46.6)	(11.0)
Change in –			
Accounts receivable and unbilled revenues	**(86.4)**	(180.7)	84.0
Materials, supplies, and inventories	**49.3**	100.0	(69.4)
Other current assets	**(6.0)**	103.1	(27.2)
Accounts payable	**8.5**	34.4	(9.3)
Other current liabilities	**161.8**	(20.8)	14.1
Other, net	**(197.5)**	(53.8)	(209.1)
Net cash provided by operating activities	**2,079.6**	2,103.5	1,293.6
Investing activities			
Capital expenditures	**(1,959.5)**	(1,423.7)	(1,266.2)
Integrys acquisition, net of cash acquired of $156.3	**—**	—	(1,329.9)
Bluewater acquisition	**(226.0)**	—	—
Capital contributions to transmission affiliates	**(109.6)**	(42.3)	(8.7)
Proceeds from the sale of assets and businesses	**24.0**	166.3	28.9
Withdrawal of restricted cash from Rabbi trust for qualifying payments	**19.5**	26.6	1.4
Other, net	**12.0**	3.0	57.0
Net cash used in investing activities	**(2,239.6)**	(1,270.1)	(2,517.5)
Financing activities			
Exercise of stock options	**30.8**	41.6	30.1
Purchase of common stock	**(71.3)**	(108.0)	(74.7)
Dividends paid on common stock	**(656.5)**	(624.9)	(455.4)
Redemption of WPS preferred stock	**—**	—	(52.7)
Issuance of long-term debt	**435.0**	400.0	2,150.0
Retirement of long-term debt	**(154.5)**	(306.0)	(529.6)
Change in short-term debt	**584.4**	(234.8)	163.0
Other, net	**(6.5)**	(13.6)	(18.9)
Net cash provided by (used in) financing activities	**161.4**	(845.7)	1,211.8
Net change in cash and cash equivalents	**1.4**	(12.3)	(12.1)
Cash and cash equivalents at beginning of year	**37.5**	49.8	61.9
Cash and cash equivalents at end of year	**$ 38.9**	$ 37.5	$ 49.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WEC ENERGY GROUP, INC.
CONSOLIDATED STATEMENTS OF EQUITY

	WEC Energy Group Common Shareholders' Equity						
(in millions, expect per share amounts)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2014	$ 2.3	$ 300.1	$ 4,117.0	$ 0.3	$ 4,419.7	$ 30.4	$ 4,450.1
Net income attributed to common shareholders	—	—	638.5	—	638.5	—	638.5
Other comprehensive income	—	—	—	4.3	4.3	—	4.3
Common stock dividends of $1.74 per share	—	—	(455.4)	—	(455.4)	—	(455.4)
Exercise of stock options	—	30.1	—	—	30.1	—	30.1
Issuance of common stock for the acquisition of Integrys	0.9	4,072.0	—	—	4,072.9	—	4,072.9
Purchase of common stock	—	(74.7)	—	—	(74.7)	—	(74.7)
Addition of WPS preferred stock	—	—	—	—	—	51.1	51.1
Redemption of WPS preferred stock	—	(1.6)	—	—	(1.6)	(51.1)	(52.7)
Stock-based compensation and other	—	21.3	(0.3)	—	21.0	—	21.0
Balance at December 31, 2015	$ 3.2	$ 4,347.2	$ 4,299.8	$ 4.6	$ 8,654.8	$ 30.4	$ 8,685.2
Net income attributed to common shareholders	—	—	939.0	—	939.0	—	939.0
Other comprehensive loss	—	—	—	(1.7)	(1.7)	—	(1.7)
Common stock dividends of $1.98 per share	—	—	(624.9)	—	(624.9)	—	(624.9)
Exercise of stock options	—	41.6	—	—	41.6	—	41.6
Purchase of common stock	—	(108.0)	—	—	(108.0)	—	(108.0)
Stock-based compensation and other	—	29.0	—	—	29.0	—	29.0
Balance at December 31, 2016	$ 3.2	$ 4,309.8	$ 4,613.9	$ 2.9	$ 8,929.8	$ 30.4	$ 8,960.2
Net income attributed to common shareholders	**—**	**—**	**1,203.7**	**—**	**1,203.7**	**—**	**1,203.7**
Common stock dividends of $2.08 per share	**—**	**—**	**(656.5)**	**—**	**(656.5)**	**—**	**(656.5)**
Exercise of stock options	**—**	**30.8**	**—**	**—**	**30.8**	**—**	**30.8**
Purchase of common stock	**—**	**(71.3)**	**—**	**—**	**(71.3)**	**—**	**(71.3)**
Cumulative effect adjustment from adoption of ASU 2016-09	**—**	**—**	**15.7**	**—**	**15.7**	**—**	**15.7**
Stock-based compensation and other	**—**	**9.2**	**—**	**—**	**9.2**	**—**	**9.2**
Balance at December 31, 2017	**$ 3.2**	**$ 4,278.5**	**$ 5,176.8**	**$ 2.9**	**$ 9,461.4**	**$ 30.4**	**$ 9,491.8**

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WEC ENERGY GROUP, INC.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*				2017	2016
Common shareholder's equity (see accompanying statement)				**$ 9,461.4**	$ 8,929.8
Preferred stock of subsidiary (Note 10)				**30.4**	30.4
Long-term debt	**Interest Rate**		**Year Due**		
WEC Energy Group Senior Notes (unsecured)	1.65%		2018	**300.0**	300.0
	2.45%		2020	**400.0**	400.0
	3.55%		2025	**500.0**	500.0
	6.20%		2033	**200.0**	200.0
WEC Energy Group Junior Notes (unsecured) (1)	3.53%		2067	**500.0**	500.0
WE Debentures (unsecured)	1.70%		2018	**250.0**	250.0
	4.25%		2019	**250.0**	250.0
	2.95%		2021	**300.0**	300.0
	3.10%		2025	**250.0**	250.0
	6.50%		2028	**150.0**	150.0
	5.625%		2033	**335.0**	335.0
	5.70%		2036	**300.0**	300.0
	3.65%		2042	**250.0**	250.0
	4.25%		2044	**250.0**	250.0
	4.30%		2045	**250.0**	250.0
	6.875%		2095	**100.0**	100.0
WPS Senior Notes (unsecured)	5.65%		2017	**—**	125.0
	1.65%		2018	**250.0**	250.0
	6.08%		2028	**50.0**	50.0
	5.55%		2036	**125.0**	125.0
	3.671%		2042	**300.0**	300.0
	4.752%		2044	**450.0**	450.0
WG Debentures (unsecured)	3.53%		2025	**200.0**	200.0
	5.90%		2035	**90.0**	90.0
	3.71%		2046	**200.0**	200.0
PGL First and Refunding Mortgage Bonds (secured) (2)	8.00%		2018	**5.0**	5.0
	4.63%		2019	**75.0**	75.0
	3.90%		2030	**50.0**	50.0
	1.875%		2033	**50.0**	50.0
	4.00%		2033	**50.0**	50.0
	3.98%		2042	**100.0**	100.0
	3.96%		2043	**220.0**	220.0
	4.21%		2044	**200.0**	200.0
	3.65%		2046	**50.0**	50.0
	3.65%		2046	**150.0**	150.0
	3.77%		2047	**100.0**	—
NSG First Mortgage Bonds (secured) (3)	3.43%		2027	**28.0**	28.0
	3.96%		2043	**54.0**	54.0
MGU Senior Notes (unsecured)	3.11%		2027	**30.0**	—
	3.41%		2032	**30.0**	—
	4.01%		2047	**30.0**	—
MERC Senior Notes (unsecured)	3.11%		2027	**40.0**	—
	3.41%		2032	**40.0**	—
	4.01%		2047	**40.0**	—
Bluewater Gas Storage Senior Notes (unsecured)	3.76%		2018-2047	**125.0**	—
We Power Subsidiaries Notes (secured, nonrecourse)	4.91%	(4)	2018-2030	**101.0**	106.7
	5.209%	(5)	2018-2030	**194.1**	204.8
	4.673%	(5)	2018-2031	**162.4**	170.9
	6.00%	(4)	2018-2033	**121.5**	126.1
	6.09%	(5)	2030-2040	**275.0**	275.0

Long-term debt (continued)	Interest Rate		Year Due	2017	2016
We Power Subsidiaries Notes (secured, nonrecourse) (continued)	5.848%	(5)	2031-2041	**215.0**	215.0
WECC Notes (unsecured)	6.94%		2028	**50.0**	50.0
Integrys Senior Notes (unsecured)	4.17%		2020	**250.0**	250.0
Integrys Junior Notes (unsecured)	3.60%	(6)	2066	**114.9**	114.9
	6.00%		2073	**400.0**	400.0
Other Notes (secured, nonrecourse)	4.81%		2030	**—**	2.0
Obligations under capital leases				**27.0**	29.6
Total				**9,627.9**	9,352.0
Integrys acquisition fair value adjustment				**26.9**	33.3
Unamortized debt issuance costs				**(38.0)**	(38.1)
Unamortized discount, net and other				**(28.1)**	(31.8)
Total long-term debt, including current portion				**9,588.7**	9,315.4
Current portion of long-term debt and capital lease obligations				**(842.1)**	(157.2)
Total long-term debt				**8,746.6**	9,158.2
Total long-term capitalization				**$ 18,238.4**	$ 18,118.4

(1) Variable interest rate reset quarterly. The rate was 3.53% as of December 31, 2017. Prior to May 15, 2017, fixed rate of 6.25%.

(2) PGL's First Mortgage Bonds are subject to the terms and conditions of PGL's First Mortgage Indenture dated January 2, 1926, as supplemented. Under the terms of the Indenture, substantially all property owned by PGL is pledged as collateral for these outstanding debt securities.

PGL has used certain First Mortgage Bonds to secure tax exempt interest rates. The Illinois Finance Authority has issued Tax Exempt Bonds, and the proceeds from the sale of these bonds were loaned to PGL. In return, PGL issued equal principal amounts of certain collateralized First Mortgage Bonds.

(3) NSG's First Mortgage Bonds are subject to the terms and conditions of NSG's First Mortgage Indenture dated April 1, 1955, as supplemented. Under the terms of the Indenture, substantially all property owned by NSG is pledged as collateral for these outstanding debt securities.

(4) We Power senior notes, secured by a collateral assignment of the leases between PWGS and WE related to PWGS 1 and PWGS 2.

(5) We Power senior notes, secured by a collateral assignment of the leases between ERGSS and WE related to ER 1 and ER 2.

(6) Variable interest rate reset quarterly. At December 31, 2017 and 2016, the rate was 3.60% and 3.05%, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WEC ENERGY GROUP, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—WEC Energy Group serves approximately 1.6 million electric customers and 2.8 million natural gas customers, and it owns approximately 60% of ATC.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the income statements, statements of comprehensive income, balance sheets, statements of cash flows, statements of equity, and statements of capitalization, unless otherwise noted.

Our financial statements include the accounts of WEC Energy Group, a diversified energy holding company, and the accounts of our subsidiaries in the following reportable segments:

- Wisconsin segment – Consists of WE, WG, and WPS, which are engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin, and UMERC, which includes WE's electric operations and WPS's electric and natural gas operations in the state of Michigan that were transferred to UMERC effective January 1, 2017.
- Illinois segment – Consists of PGL and NSG, which are engaged primarily in the distribution of natural gas in Illinois.
- Other states segment – Consists of MERC and MGU, which are engaged primarily in the distribution of natural gas in Minnesota and Michigan, respectively.
- Electric transmission segment – Consists of our approximate 60% ownership interest in ATC, a federally regulated electric transmission company.
- Non-utility energy infrastructure segment – Consists of We Power, which is principally engaged in the ownership of electric power generating facilities for long-term lease to WE, and Bluewater, which owns underground natural gas storage facilities in Michigan. See Note 2, Acquisitions, for more information on the June 2017 Bluewater transaction.
- Corporate and other segment – Consists of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Bostco, Wisvest, WECC, WBS, PDL, and ITF. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco and in the second quarter of 2016, we sold certain assets of Wisvest. The sale of ITF was completed in the first quarter of 2016. See Note 3, Dispositions, for more information on these sales.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 6, Jointly Owned Facilities, for more information. The cost method of accounting is used for investments when we do not have significant influence over the operating and financial policies of the investee. Investments in companies not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method.

(b) Basis of Presentation—We prepare our financial statements in conformity with GAAP. We make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

(c) Cash and Cash Equivalents—Cash and cash equivalents include marketable debt securities with an original maturity of three months or less.

(d) Revenues and Customer Receivables—We recognize revenues related to the sale of energy on the accrual basis and include estimated amounts for services provided but not yet billed to customers.

We present revenues net of pass-through taxes on the income statements.

Below is a summary of the significant mechanisms our utility subsidiaries had in place that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts:

- Fuel and purchased power costs were recovered from customers on a one-for-one basis by our Wisconsin wholesale electric operations and our Michigan retail electric operations.
- Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. The electric fuel rules set by the PSCW allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs that exceed a 2% price variance from the costs included in the rates

charged to customers. Our electric utilities monitor the deferral of under-collected costs to ensure that it does not cause them to earn a greater ROE than authorized by the PSCW.

- WE received payments from MISO under an SSR agreement for its PIPP units through February 1, 2015. We recorded revenue for these payments to recover costs for operating and maintaining these units. See Note 23, Regulatory Environment, for more information.
- The rates for all of our natural gas utilities included one-for-one recovery mechanisms for natural gas commodity costs. We defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.
- The rates of PGL and NSG included riders for cost recovery of both environmental cleanup costs and energy conservation and management program costs.
- MERC's rates included a conservation improvement program rider for cost recovery of energy conservation and management program costs as well as a financial incentive for meeting energy savings goals.
- The rates of PGL and NSG, and the residential rates of WE and WG, included riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates.
- The rates of PGL, NSG, MERC, and MGU included decoupling mechanisms. These mechanisms differ by state and allow utilities to recover or refund differences between actual and authorized margins. MGU's decoupling mechanism was discontinued after December 31, 2015. See Note 23, Regulatory Environment, for more information.
- PGL's rates included a cost recovery mechanism for SMP costs.

Revenues are also impacted by other accounting policies related to our electric utilities' participation in the MISO Energy Markets. Our electric utilities sell and purchase power in the MISO Energy Markets, which operate under both day-ahead and real-time markets. We record energy transactions in the MISO Energy Markets on a net basis for each hour. If our electric utilities were a net seller in a particular hour, the net amount was reported as operating revenues. If our electric utilities were a net purchaser in a particular hour, the net amount was recorded as cost of sales on our income statements.

We provide regulated electric service to customers in Wisconsin and Michigan and regulated natural gas service to customers in Wisconsin, Illinois, Minnesota, and Michigan. The geographic concentration of our customers did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements, and historical payment performance and require them to provide collateral or other security as needed. Credit risk exposure at WE, WG, PGL, and NSG is mitigated by their recovery mechanisms for uncollectible expense discussed above. As a result, we did not have any significant concentrations of credit risk at December 31, 2017. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2017.

(e) Materials, Supplies, and Inventories—Our inventory as of December 31 consisted of:

(in millions)	2017	2016
Natural gas in storage	**$ 209.0**	$ 223.1
Materials and supplies	**211.2**	206.5
Fossil fuel	**118.8**	158.0
Total	**$ 539.0**	$ 587.6

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 15% and 18% of total inventories at December 31, 2017 and 2016, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2017 and 2016, exceeded the LIFO cost by $152.1 million and $92.9 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $4.68 at December 31, 2017, and $3.63 at December 31, 2016.

Substantially all other natural gas in storage, materials and supplies, and fossil fuel inventories are recorded using the weighted-average cost method of accounting.

(f) Investments Held in Rabbi Trust— Integrys has a rabbi trust that is used to fund participants' benefits under the Integrys deferred compensation plan and certain Integrys non-qualified pension plans. All assets held within the rabbi trust are restricted as they can only be withdrawn from the trust to make qualifying benefit payments. The trust holds investments that are classified as trading securities for accounting purposes. As we do not intend to sell the investments in the near term, they are included in other long-term assets on our balance sheets. The net unrealized gains included in earnings related to the investments held at the end of the period were $18.8 million for the year ended December 31, 2017. The net unrealized gains and losses included in earnings for the years ended December 31, 2016 and 2015 were not significant.

(g) Regulatory Assets and Liabilities—The economic effects of regulation can result in regulated companies recording costs and revenues that have been or are expected to be allowed in the rate-making process in a period different from the period in which the costs or revenues would be recognized by a nonregulated company. When this occurs, regulatory assets and regulatory liabilities are recorded on the balance sheet. Regulatory assets represent probable future revenues associated with certain costs or liabilities that have been deferred and are expected to be recovered through rates charged to customers. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts that are collected in rates for future costs.

Recovery or refund of regulatory assets and liabilities is based on specific periods determined by the regulators or occurs over the normal operating period of the assets and liabilities to which they relate. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the reporting period the determination is made. See Note 4, Regulatory Assets and Liabilities, for more information.

(h) Property, Plant, and Equipment—We record property, plant, and equipment at cost. Cost includes material, labor, overhead, and both debt and equity components of AFUDC. Additions to and significant replacements of property are charged to property, plant, and equipment at cost; minor items are charged to other operation and maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We record straight-line depreciation expense over the estimated useful life of utility property using depreciation rates approved by the applicable regulators. Annual utility composite depreciation rates are shown below:

Annual Utility Composite Depreciation Rates	2017	2016	2015
WE	2.95%	3.00%	3.01%
WPS (1)	2.55%	2.58%	1.30%
WG	2.30%	2.34%	2.36%
UMERC (2)	2.46%	N/A	N/A
PGL (1)	3.29%	3.31%	1.67%
NSG (1)	2.43%	2.44%	1.22%
MERC (1)	2.51%	2.53%	1.26%
MGU (1)	2.61%	2.63%	1.32%

(1) The rates shown for 2015 are for a partial year as a result of the acquisition of Integrys. The full year rate would be approximately double the rate shown.

(2) UMERC became operational effective January 1, 2017. See Note 1(a), Nature of Operations, for more information.

We depreciate our We Power assets over the estimated useful life of the various property components. The components have useful lives of between 10 to 45 years for PWGS 1 and PWGS 2 and 10 to 55 years for ER 1 and ER 2.

We capitalize certain costs related to software developed or obtained for internal use and record these costs to amortization expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

Third parties reimburse the utilities for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs are recorded as a reduction to property, plant, and equipment.

See Note 5, Property, Plant, and Equipment, for more information.

(i) Allowance for Funds Used During Construction—AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC – Debt) used during plant construction, and a return on shareholders' capital (AFUDC – Equity) used for construction purposes. AFUDC – Debt is recorded as a reduction of interest expense, and AFUDC – Equity is recorded in other income, net.

The majority of AFUDC is recorded at WE, WPS, WBS, and WG. Approximately 50% of WE's, WPS's, WBS's, and WG's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. The AFUDC calculation for WBS uses the WPS AFUDC retail rate, while the other utilities AFUDC rates are determined by their respective state commissions, each with specific requirements. Based on these requirements, the other utilities did not record significant AFUDC for 2017, 2016, or 2015. Average AFUDC rates are shown below:

	2017	
	Average AFUDC Retail Rate	**Average AFUDC Wholesale Rate**
WE	8.45%	5.94%
WPS	7.72%	1.01%
WBS	7.72%	N/A
WG	8.33%	N/A

Our regulated utilities and WBS recorded the following AFUDC for the years ended December 31:

(in millions)	**2017**	2016	2015
AFUDC – Debt	**$ 4.9**	$ 10.9	$ 8.6
AFUDC – Equity	**$ 11.4**	$ 25.1	$ 20.1

(j) Asset Impairment—Goodwill and other intangible assets with indefinite lives are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Our reporting units containing goodwill perform annual goodwill impairment tests during the third quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. See Note 8, Goodwill, for more information. Intangible assets with definite lives are reviewed for impairment on a quarterly basis.

We periodically assess the recoverability of certain long-lived assets when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include certain assets within regulated operations that may not be fully recovered from our customers as a result of regulatory decisions that will be made in the future, and assets within nonregulated operations that are proposed to be sold or are currently generating operating losses.

An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds the fair value of the asset. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset.

When it becomes probable that a generating unit will be retired before the end of its useful life, we assess whether the generating unit meets the criteria for abandonment accounting. Generating units that are considered probable of abandonment are expected to cease operations in the near term, significantly before the end of their original estimated useful lives. If a generating unit meets applicable criteria to be considered probable of abandonment, we assess the likelihood of recovery of the remaining carrying value of that generating unit at the end of each reporting period. If it becomes probable that regulators will disallow full recovery as well as a return on the remaining net book value of the abandoned generating unit, an impairment charge may be required. An impairment charge would be recorded if the remaining carrying value of the abandoned generating unit is greater than the present value of the amount expected to be recovered from ratepayers. See Note 5, Property, Plant, and Equipment, for more information.

The carrying amounts of cost and equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying amounts, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists and it is determined to be other-than-temporary, a loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

(k) Asset Retirement Obligations—We recognize, at fair value, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of the assets. An ARO liability is recorded, when incurred, for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The associated retirement costs are capitalized as part of the related long-lived asset and are depreciated over the useful life of the asset. The ARO liabilities are accreted each period using the credit-adjusted risk-free interest rates associated with the expected settlement dates of the AROs. These rates are determined when the obligations are incurred. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease to the carrying amount of the liability and the associated retirement costs. For our regulated entities, we recognize regulatory assets or liabilities for the timing differences between when we recover an ARO in rates and when we recognize the associated retirement costs. See Note 7, Asset Retirement Obligations, for more information.

(l) Stock-Based Compensation— In accordance with the shareholder approved Omnibus Stock Incentive Plan, we provide long-term incentives through our equity interests to our non-employee directors, officers, and other key employees. The plan provides for the granting of stock options, restricted stock, performance shares, and other stock-based awards. Awards may be paid in common stock, cash, or a combination thereof. The number of shares of common stock authorized for issuance under the plan is 34.3 million.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period. Awards classified as equity awards are measured based on their grant-date fair value. Awards classified as liability awards are recorded at fair value each reporting period.

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, which modifies certain aspects of the accounting for stock-based compensation awards. This ASU became effective for us on January 1, 2017. Under the new guidance, all excess tax benefits and tax deficiencies are recognized as income tax expense or benefit in the income statement on a prospective basis. Prior to January 1, 2017, these amounts were recorded in additional paid in capital on the balance sheet, and excess tax benefits could only be recognized to the extent they reduced taxes payable. In the first quarter of 2017, we recorded a $15.7 million cumulative-effect adjustment to increase retained earnings for excess tax benefits that had not been recognized in prior years as they did not reduce taxes payable.

ASU 2016-09 also requires excess tax benefits to be classified as an operating activity on the statement of cash flows. As we have elected to apply this provision on a prospective basis, the prior year amounts will continue to be reflected as a financing activity. As allowed under this ASU, we have also elected to account for forfeitures as they occur, rather than estimating potential future forfeitures and recording them over the vesting period.

Stock Options

We grant non-qualified stock options that generally vest on a cliff-basis after a three-year period. The exercise price of a stock option under the plan cannot be less than 100% of our common stock's fair market value on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market value of our common stock on the date of the grant. Options may not be exercised within six months of the grant date except in the event of a change in control. Options expire no later than 10 years from the date of the grant.

Our stock options are classified as equity awards. The fair value of our stock options was calculated using a binomial option-pricing model. The following table shows the estimated weighted-average fair value per stock option granted along with the weighted-average assumptions used in the valuation models:

	2017	2016	2015
Stock options granted	**552,215**	794,764	516,475
Estimated weighted-average fair value per stock option	**$ 7.45**	$ 5.14	$ 5.29
Assumptions used to value the options:			
Risk-free interest rate	**0.7% – 2.5%**	0.4% – 2.2%	0.1% – 2.1%
Dividend yield	**3.5%**	4.0%	3.7%
Expected volatility	**19.0%**	18.1%	18.0%
Expected life (years)	**6.8**	6.1	5.8

The risk-free interest rate was based on the United States Treasury interest rate with a term consistent with the expected life of the stock options. The dividend yield was based on our dividend rate at the time of the grant and historical stock prices. Expected volatility and expected life assumptions were based on our historical experience.

Restricted Shares

Restricted shares granted to employees have a three-year vesting period with one-third of the award vesting on each anniversary of the grant date. This same vesting schedule is followed for restricted shares that were granted to non-employee directors prior to 2017. Restricted shares granted to non-employee directors after January 1, 2017, fully vest on the one-year anniversary of the grant date.

Our restricted shares are classified as equity awards.

Performance Units

Officers and other key employees are granted performance units under the WEC Energy Group Performance Unit Plan. Under the plan, the ultimate number of units that will be awarded is dependent on our total shareholder return (stock price appreciation plus dividends) as compared to the total shareholder return of a peer group of companies over a three-year period, and beginning in 2017, other performance metrics as determined by the Compensation Committee. Under the terms of the award, participants may earn between 0% and 175% of the performance unit award, as adjusted pursuant to the terms of the plan. Performance units granted on or after January 1, 2016 also accrue forfeitable dividend equivalents in the form of additional performance units.

All grants of performance units are settled in cash and are accounted for as liability awards accordingly. The fair value of the performance units reflects our estimate of the final expected value of the awards, which is based on our stock price and performance achievement under the terms of the award. Stock-based compensation costs are recorded over the three-year performance period.

See Note 9, Common Equity, for more information on our stock-based compensation plans.

(m) Earnings Per Share—We compute basic earnings per share by dividing our net income attributed to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities. Such dilutive securities include in-the-money stock options. The calculation of diluted earnings per share for the years ended December 31, 2016 and 2015 excluded 181,709 and 516,475 stock options, respectively, that had an anti-dilutive effect. There were no securities that had an anti-dilutive effect for the year ended December 31, 2017.

(n) Deferred Revenue—As part of the construction of We Power's electric generating units, we capitalized interest during construction. As allowed under the lease agreements, we were able to collect the carrying costs during the construction of these generating units from our utility customers. The carrying costs that we collected during construction have been recorded as deferred revenue on our balance sheets and we are amortizing the deferred carrying costs to revenue over the individual lease terms.

(o) Income Taxes—We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

Investment tax credits associated with regulated operations are deferred and amortized over the life of the assets. We file a consolidated Federal income tax return. Accordingly, we allocate Federal current tax expense benefits and credits to our subsidiaries based on their separate tax computations. See Note 13, Income Taxes, for more information.

We recognize interest and penalties accrued, related to unrecognized tax benefits, in income tax expense in our income statements.

(p) Fair Value Measurements—Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

Fair value accounting rules provide a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methods.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methods that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. We use a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing certain derivative assets and liabilities. We primarily use a market approach for recurring fair value measurements and attempt to use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

When possible, we base the valuations of our derivative assets and liabilities on quoted prices for identical assets and liabilities in active markets. These valuations are classified in Level 1. The valuations of certain contracts not classified as Level 1 may be based on quoted market prices received from counterparties and/or observable inputs for similar instruments. Transactions valued using these inputs are classified in Level 2. Certain derivatives are categorized in Level 3 due to the significance of unobservable or internally-developed inputs.

Derivatives were transferred between levels of the fair value hierarchy primarily due to observable pricing becoming available. We recognize transfers between levels of the fair value hierarchy at their value as of the end of the reporting period.

Due to the short-term nature of cash and cash equivalents, net accounts receivable and unbilled revenues, accounts payable, and short-term debt, the carrying amount of each such item approximates fair value. The fair value of our preferred stock is estimated based on the quoted market value for the same issue, or by using a dividend discount model. The fair value of our long-term debt is estimated based upon the quoted market value for the same issue, similar issues, or upon the quoted market prices of United States Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. The fair values of long-term debt and preferred stock are categorized within Level 2 of the fair value hierarchy.

See Note 14, Fair Value Measurements, for more information.

(q) Derivative Instruments—We use derivatives as part of our risk management program to manage the risks associated with the price volatility of purchased power, generation, and natural gas costs for the benefit of our customers and shareholders. Our approach is non-speculative and designed to mitigate risk. Regulated hedging programs are approved by our state regulators.

We record derivative instruments on our balance sheets as assets or liabilities measured at fair value unless they qualify for the normal purchases and sales exception, and are so designated. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy-related physical and financial contracts in our regulated operations that qualify as derivatives, our regulators allow the effects of fair value accounting to be offset to regulatory assets and liabilities.

We classify derivative assets and liabilities as current or long-term on our balance sheets based on the maturities of the underlying contracts. Realized gains and losses on derivative instruments are primarily recorded in cost of sales on the income statements. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on our statements of cash flows.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets, and cash collateral received is reflected in other current liabilities. See Note 15, Derivative Instruments, for more information.

(r) Guarantees— We follow the guidance of the Guarantees Topic of the FASB ASC, which requires that the guarantor recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. See Note 16, Guarantees, for more information.

(s) Employee Benefits—The costs of pension and OPEB are expensed over the periods during which employees render service. These costs are distributed among our subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the utilities' net periodic benefit cost calculated under GAAP. See Note 17, Employee Benefits, for more information.

(t) Customer Deposits and Credit Balances—When utility customers apply for new service, they may be required to provide a deposit for the service. Customer deposits are recorded within other current liabilities on our balance sheets.

Utility customers can elect to be on a budget plan. Under this type of plan, a monthly installment amount is calculated based on estimated annual usage. During the year, the monthly installment amount is reviewed by comparing it to actual usage. If necessary, an adjustment is made to the monthly amount. Annually, the budget plan is reconciled to actual annual usage. Payments in excess of actual customer usage are recorded within other current liabilities on our balance sheets.

(u) Environmental Remediation Costs—We are subject to federal and state environmental laws and regulations that in the future may require us to pay for environmental remediation at sites where we have been, or may be, identified as a potentially responsible party. Loss contingencies may exist for the remediation of hazardous substances at various potential sites, including coal combustion product landfill sites and manufactured gas plant sites. See Note 7, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 21, Commitments and Contingencies, for more information regarding manufactured gas plant sites.

We record environmental remediation liabilities when site assessments indicate remediation is probable and we can reasonably estimate the loss or a range of losses. The estimate includes both our share of the liability and any additional amounts that will not be paid by other potentially responsible parties or the government. When possible, we estimate costs using site-specific information but also consider historical experience for costs incurred at similar sites. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, potentially affecting the cost of remediation.

Our utilities have received approval to defer certain environmental remediation costs, as well as estimated future costs, through a regulatory asset. The recovery of deferred costs is subject to the applicable state Commission's approval.

We review our estimated costs of remediation annually for our manufactured gas plant sites and coal combustion product landfill sites. We adjust the liabilities and related regulatory assets, as appropriate, to reflect the new cost estimates. Any material changes in cost estimates are adjusted throughout the year.

NOTE 2—ACQUISITIONS

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, WPS, along with two other unaffiliated utilities, entered into an agreement to purchase the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MW. The aggregate purchase price is approximately $174 million of which WPS's proportionate share is 44.6%, or approximately $78 million. WPS currently purchases 44.6% of the facility's energy output under a power purchase agreement. The FERC approved the transaction on January 16, 2018. The transaction remains subject to PSCW approval and is expected to close in the spring of 2018.

Acquisition of Natural Gas Storage Facilities in Michigan

On June 30, 2017, we completed the acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that will provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities. In addition, we incurred $4.9 million of acquisition related costs.

The table below shows the preliminary allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition. The allocation is subject to change during the remainder of the measurement period, which ends one year from the acquisition date, as we obtain additional information. The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. Bluewater is included in the non-utility energy infrastructure segment. Bluewater is regulated by the FERC. Its operations meet the criteria, and accordingly, are accounted for following the accounting guidance under the Regulated Operations Topic of the FASB ASC. See Note 19, Segment Information, for more information.

(in millions)		
Current assets	$	2.0
Property, plant, and equipment, net		217.6
Goodwill		7.3
Current liabilities		(0.9)
Total purchase price	**$**	**226.0**

Acquisition of Integrys

On June 29, 2015, Wisconsin Energy Corporation acquired 100% of the outstanding common shares of Integrys and changed its name to WEC Energy Group, Inc. Integrys is a provider of regulated natural gas and electricity, as well as nonregulated renewable energy products and services. Integrys also provided CNG products and services prior to the sale of ITF in the first quarter of 2016. Integrys held a 34% interest in ATC, a for-profit transmission company regulated by the FERC, which has since been moved to another of our subsidiaries. The acquisition of Integrys has provided increased scale, operating efficiencies, and the potential for long-term cost savings through a combination of lower capital and operating costs.

Purchase Price

Pursuant to the Merger Agreement, Integrys's shareholders received 1.128 shares of Wisconsin Energy Corporation common stock and $18.58 in cash per share of Integrys common stock. The total consideration transferred was based on the closing price of Wisconsin Energy Corporation common stock on June 29, 2015, and was calculated as follows:

	Consideration Paid		
(in millions, except per share amounts)	**Stock**	**Cash**	**Total**
Integrys common shares outstanding at June 29, 2015	79,963,091	79,963,091	
Exchange ratio	1.128		
Wisconsin Energy Corporation shares issued for Integrys shares *	90,187,884		
Closing price of Wisconsin Energy Corporation common shares on June 29, 2015	$45.16		
Fair value of common stock issued	$ 4,072.9		$ 4,072.9
Cash paid per share of Integrys shares outstanding		$18.58	
Fair value of cash paid for Integrys shares *		$ 1,486.2	$ 1,486.2
Consideration attributable to settlement of equity awards, net of tax		$ 24.0	$ 24.0
Total purchase price	$ 4,072.9	$ 1,510.2	$ 5,583.1

* Fractional shares of 10,483 totaling $0.5 million were paid in cash.

All Integrys unvested stock-based compensation awards became fully vested upon the close of the acquisition and were either paid to award recipients in cash, or the value of the awards was deferred into a deferred compensation plan. In addition, all vested but unexercised Integrys stock options were paid in cash. In accordance with accounting guidance for business combinations, the acceleration of the vesting was recorded as an acquisition-related expense.

Allocation of Purchase Price

The Integrys assets acquired and liabilities assumed were measured at estimated fair value in accordance with the accounting guidance under the Business Combinations Topic in the FASB ASC. Substantially all of Integrys's operations are subject to the rate-setting authority of federal and state regulatory commissions. These operations are accounted for following the accounting guidance under the Regulated Operations Topic of the FASB ASC. The underlying assets and liabilities of ATC are also regulated by the FERC. Integrys's assets and liabilities that are subject to rate-setting provisions provide revenues derived from costs, including a return on investment of assets less liabilities included in rate base. As such, the fair values of these assets and liabilities equal their carrying values. Accordingly, neither the assets and liabilities acquired, nor the pro forma financial information, reflect any adjustments related to these amounts.

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. The goodwill reflects the value paid for the increased scale and efficiencies as a result of the combination. The goodwill recognized is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to goodwill. See Note 8, Goodwill, for the allocation of goodwill to our reportable segments.

During the first six months of 2016, adjustments were made to the estimated fair values of the assets acquired and liabilities assumed, primarily in connection with the sale of ITF and reserves recorded for likely settlements of certain legal and regulatory matters. The table below shows the final allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition:

(in millions)	
Current assets	**$ 1,060.1**
Property, plant, and equipment, net	**7,107.4**
Goodwill	**2,604.3**
Other long-term assets *	**2,830.5**
Current liabilities	**(1,320.7)**
Long-term debt	**(2,943.6)**
Other long-term liabilities	**(3,703.8)**
Preferred stock of subsidiary	**(51.1)**
Total purchase price	**$ 5,583.1**

* Includes equity method goodwill related to Integrys's investment in ATC. See Note 18, Investment in Transmission Affiliates, for more information.

In September 2015, the FASB issued ASU 2015-16, Simplifying the Accounting for Measurement-Period Adjustments, which requires that an acquirer recognize and disclose adjustments to provisional amounts that are identified during an acquisition measurement period in the reporting period in which the adjustment amounts are determined. ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. Early adoption was permitted for any interim and annual financial statements that had not yet been issued. We early adopted ASU 2015-16 in the fourth quarter of 2015. Adoption had no impact on our financial statements.

Conditions of Approval

The acquisition was subject to the approvals of various government agencies, including the FERC, Federal Communications Commission, PSCW, ICC, MPSC, and MPUC. Approvals were obtained from all agencies subject to several conditions.

The PSCW order includes the following conditions:

- WE and WG are each subject to an earnings sharing mechanism for three years beginning January 1, 2016. Under the earnings sharing mechanisms, if either company earns above its authorized return, 50% of the first 50 basis points of additional utility earnings will be shared with customers. For WE, the additional utility earnings will be used to reduce the company's transmission escrow. For WG, additional utility earnings will be used to reduce the costs of its Western Gas Lateral project that would otherwise be included in rates. All utility earnings above the first 50 basis points will be used to reduce the transmission escrow for WE and reduce the costs of the Western Gas Lateral that would otherwise be included in rates for WG. For the years ended December 31, 2017 and 2016, WE and WG recorded a combined $2.9 million and $24.4 million of expense related to these earnings sharing mechanisms, respectively.
- Any future electric generation projects affecting Wisconsin ratepayers submitted by us or our subsidiaries will first consider the extent to which existing intercompany resources can meet energy and capacity needs. In September 2015, WPS and WE filed a joint integrated resource plan with the PSCW for their combined loads, which indicated that no new generation was needed at the time.

The ICC order included a base rate freeze for PGL and NSG effective for two years after the close of the acquisition. This base rate freeze expired in 2017 and did not impact PGL's or NSG's ability to adjust rates through various riders or GCRMs.

Pro Forma Information

The following unaudited pro forma financial information reflects the consolidated results and amortization of purchase price adjustments as if the acquisition had taken place on January 1, 2014. The unaudited pro forma financial information is presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or our future consolidated results.

The pro forma financial information does not reflect any potential cost savings from operating efficiencies resulting from the acquisition and does not include certain acquisition-related costs.

(in millions, except per share amounts)	**Year ended December 31, 2015**
Unaudited pro forma financial information	
Operating revenues	$ 7,727.1
Net income attributed to common shareholders	$ 873.5
Earnings per share (Basic)	$ 2.77
Earnings per share (Diluted)	$ 2.75

Impact of Acquisition

As a result of the acquisition, our ownership of ATC increased to approximately 60%. We have made commitments with respect to our voting rights of the combined ownership of ATC, which are included as enforceable conditions in the FERC and PSCW orders approving the acquisition. Under GAAP, these commitments do not allow for the consolidation of ATC in our financial statements and the 60% ownership is accounted for as an equity method investment subsequent to the close of the acquisition. See Note 18, Investment in Transmission Affiliates, for more information.

In connection with the acquisition, WEC Energy Group and its subsidiaries recorded pre-tax acquisition costs of $3.5 million and $107.6 million during 2016 and 2015, respectively. These costs consisted of employee-related expenses, professional fees, and other miscellaneous costs. They are primarily recorded in the other operation and maintenance line item on the income statements.

Included in the 2015 acquisition costs was $24.9 million of severance expense that resulted from employee reductions related to the post-acquisition integration. Severance expense incurred after 2015 was not significant. The 2015 severance expense was recorded in the following segments:

(in millions)	Year ended December 31, 2015
Wisconsin	$ 11.1
Illinois	0.9
Other states	0.1
Corporate and other	12.8
Total severance expense	$ 24.9

Severance payments made during 2017 were not significant. Severance payments of $7.5 million and $16.9 million were made during 2016 and 2015, respectively. The severance accrual on our balance sheets at December 31, 2017 and 2016 related to the acquisition of Integrys was not significant.

Our revenues for the year ended December 31, 2015 include revenues attributable to Integrys of $1,416.8 million. Included in our net income for the year ended December 31, 2015, is net income attributable to Integrys of $65.9 million.

NOTE 3—DISPOSITIONS

Wisconsin Segment

Sale of Milwaukee County Power Plant

In April 2016, we sold the MCPP steam generation and distribution assets, located in Wauwatosa, Wisconsin. MCPP primarily provided steam to the Milwaukee Regional Medical Center hospitals and other campus buildings. During the second quarter of 2016, we recorded a pre-tax gain on the sale of $10.9 million ($6.5 million after tax), which was included in other operation and maintenance on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations of this plant remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

Corporate and Other Segment

Sale of Bostco Real Estate Holdings

In March 2017, we sold the remaining real estate holdings of Bostco located in downtown Milwaukee, Wisconsin, which included retail, office, and residential space. During the first quarter of 2017, we recorded an insignificant gain on the sale, which was included in other income, net on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations associated with these assets remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

Sale of Certain Assets of Wisvest

In April 2016, as part of the MCPP sale transaction, we sold the chilled water generation and distribution assets of Wisvest, which are used to provide chilled water services to the Milwaukee Regional Medical Center hospitals and other campus buildings. During the second quarter of 2016, we recorded a pre-tax gain on the sale of $19.6 million ($11.8 million after tax), which was included in other income, net on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations associated with these assets remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

Sale of Integrys Transportation Fuels

Through a series of transactions in the fourth quarter of 2015 and the first quarter of 2016, we sold ITF, a provider of CNG fueling services and a single-source provider of CNG fueling facility design, construction, operation, and maintenance. There was no gain or loss recorded on the sales, as ITF's assets and liabilities were adjusted to fair value through purchase accounting. The results of operations of ITF remained in continuing operations through the sale date as the sale of ITF did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results. The pre-tax profit or loss of this component was not material through the sale date in 2016.

NOTE 4—REGULATORY ASSETS AND LIABILITIES

We recorded a $2,450 million change in our deferred taxes for our regulated utilities due to the enactment of the Tax Legislation, which resulted in both an increase to income tax related regulatory liabilities as well as a decrease to certain existing income tax related regulatory assets represented in Income tax related items in the table below. The $2,450 million change in our deferred taxes represents our estimate of the tax benefit that will be returned to ratepayers through future refunds, bill credits, riders, or reductions in other regulatory assets. See Note 13, Income Taxes, for more information on the Tax Legislation.

The following regulatory assets were reflected on our balance sheets as of December 31:

(in millions)	2017	2016	See Note
Regulatory assets [1] [2]			
Unrecognized pension and OPEB costs [3]	**$ 1,142.0**	$ 1,252.1	17
Environmental remediation costs [4]	**676.6**	702.7	21
SSR	**298.9**	188.1	23
Electric transmission costs	**221.0**	234.1	23
AROs	**192.2**	179.2	7
We Power generation [5]	**71.3**	54.1	
Uncollectible expense [6]	**35.1**	25.6	1(d)
Energy efficiency programs [7]	**24.6**	36.7	
Income tax related items	**15.7**	285.1	13
Other, net	**163.0**	180.6	
Total regulatory assets	**$ 2,840.4**	$ 3,138.3	
Balance Sheet Presentation			
Current assets [8]	**$ 37.2**	$ 50.4	
Regulatory assets	**2,803.2**	3,087.9	
Total regulatory assets	**$ 2,840.4**	$ 3,138.3	

(1) Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in the table.

(2) As of December 31, 2017, we had $116.9 million of regulatory assets not earning a return and $261.1 million of regulatory assets earning a return based on short-term interest rates. The regulatory assets not earning a return primarily relate to certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures, as well as certain unrecognized pension and OPEB costs, unamortized loss on reacquired debt, and plant-related costs. The other regulatory assets in the table either earn a return or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

(3) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans. We are authorized recovery of this regulatory asset over the average remaining service life of each plan.

(4) As of December 31, 2017, we had not yet made cash expenditures for $617.4 million of these environmental remediation costs.

(5) Represents amounts recoverable from customers related to WE's costs of the generating units leased from We Power, including subsequent capital additions.

(6) Represents amounts recoverable from customers related to our uncollectible expense tracking mechanisms and riders. These mechanisms allow us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

(7) Represents amounts recoverable from customers related to programs at the utilities designed to meet energy efficiency standards.

(8) Short-term regulatory assets are recorded in accounts receivable and unbilled revenues on our balance sheets.

The following regulatory liabilities were reflected on our balance sheets as of December 31:

(in millions)	2017	2016	See Note
Regulatory liabilities			
2017 Tax Legislation impact and income tax related	**$ 2,134.1**	$ —	13
Removal costs [1]	**1,294.9**	1,262.7	
Unrecognized pension and OPEB costs [2]	**114.2**	63.0	17
Mines deferral [3]	**95.1**	70.2	
Energy costs refundable through rate adjustments [4]	**42.0**	88.7	
Uncollectible expense [5]	**24.7**	36.1	1(d)
Derivatives	**11.0**	41.1	1(q)
Other, net	**44.4**	35.4	
Total regulatory liabilities	**$ 3,760.4**	$ 1,597.2	
Balance Sheet Presentation			
Current liabilities	**$ 41.8**	$ 33.4	
Regulatory liabilities	**3,718.6**	1,563.8	
Total regulatory liabilities	**$ 3,760.4**	$ 1,597.2	

(1) Represents amounts collected from customers to cover the cost of future removal of property, plant, and equipment.

(2) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans. We will amortize this regulatory liability into net periodic benefit cost over the average remaining service life of each plan.

(3) Represents the deferral of revenues less the associated cost of sales related to sales to the mines, which were not included in the 2015 rate order. We intend to request that this deferral be applied for the benefit of Wisconsin retail electric customers in a future rate proceeding.

(4) Represents energy costs that will be refunded to customers in the future.

(5) Represents amounts refundable to customers related to our uncollectible expense tracking mechanisms and riders. These mechanisms allow us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

NOTE 5—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following utility and non-utility and other assets at December 31:

(in millions)	2017	2016
Utility property, plant, and equipment	**$ 23,646.7**	$ 24,185.1
Less: Accumulated depreciation	**7,021.8**	7,609.7
Net	**16,624.9**	16,575.4
CWIP	**508.2**	320.0
Plant to be retired, net	**930.6**	—
Net utility property, plant, and equipment	**18,063.7**	16,895.4
Non-utility and other property, plant, and equipment	**3,797.2**	3,520.3
Less: Accumulated depreciation	**671.3**	604.9
Net	**3,125.9**	2,915.4
CWIP	**157.4**	104.7
Net non-utility and other property, plant, and equipment	**3,283.3**	3,020.1
Total property, plant, and equipment	**$ 21,347.0**	$ 19,915.5

Wisconsin Segment Plant to be Retired

We have evaluated future plans for our older and less efficient fossil fuel generating units and have announced the retirement of the plants identified below. The net book value of these plants was classified as plant to be retired within property, plant, and equipment on our balance sheet at December 31, 2017. In addition, severance expense in the amount of $29.4 million was recorded within the Wisconsin segment in 2017 related to these announced plant retirements.

Pleasant Prairie Power Plant

As a result of a MISO ruling in December 2017, Pleasant Prairie must be shut down no later than April 10, 2018. Because we had an obligation at December 31, 2017 to shut down the Pleasant Prairie plant in April 2018, retirement of the plant was probable at December 31, 2017. The net book value of this generating unit was $681.3 million at December 31, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. This unit is included in rate base, and WE continues to depreciate it on a straight-line basis using the composite depreciation rates approved by the

PSCW. The physical dismantlement of the plant will not occur immediately. It may take several years to finalize long-term plans for the site. See Note 21, Commitments and Contingencies, for more information.

Presque Isle Power Plant

In October 2017, the MPSC approved UMERC's application to construct and operate approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan. Upon receiving this approval, retirement of the PIPP generating units became probable. The new units are expected to begin commercial operation in 2019 and should allow for the retirement of PIPP no later than 2020. The net book value of these units was $191.4 million at December 31, 2017. These units are included in rate base, and WE continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. The net book value of these assets was transferred from plant in service to plant to be retired. See Note 23, Regulatory Environment, for more information regarding the new natural gas-fired generation.

Pulliam Power Plant

As a result of MISO's ruling that WPS will be able retire the Pulliam generating units when certain transmission lines are completed, expected near the end of 2018, retirement of the Pulliam generating units was probable at December 31, 2017. The net book value of these generating units was $44.9 million at December 31, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. These units are included in rate base, and WPS continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. See Note 21, Commitments and Contingencies, for more information.

Edgewater Unit 4

As a result of the continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, retirement of the Edgewater 4 generating unit was probable at December 31, 2017. WPS anticipates that the plant will be retired by September 30, 2018. The net book value of WPS's ownership share of this generating unit was $13.0 million at December 31, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. This unit is included in rate base, and WPS continues to depreciate it on a straight-line basis using the composite depreciation rates approved by the PSCW. See Note 21, Commitments and Contingencies, for more information regarding the Consent Decree.

NOTE 6—JOINTLY OWNED FACILITIES

We Power and WPS hold joint ownership interests in certain electric generating facilities. They are entitled to their share of generating capability and output of each facility equal to their respective ownership interest. They pay their ownership share of additional construction costs and have supplied their own financing for all jointly owned projects. We record We Power's and WPS's proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets.

We Power leases its ownership interest in ER 1 and ER 2 to WE, and WE operates these units. WE and WPS record their respective share of fuel inventory purchases and operating expenses, unless specific agreements have been executed to limit their maximum exposure to additional costs. WE's and WPS's proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements.

Information related to jointly owned facilities at December 31, 2017 was as follows:

	We Power	WPS		
(in millions, except for percentages and MW)	Elm Road Generating Station Units 1 and 2	Weston Unit 4	Columbia Energy Center Units 1 and 2 (2)	Edgewater Unit 4 (3)
Ownership	83.34%	70.0%	29.5%	31.8%
Share of rated capacity (MW) (1)	1,056.8	383.9	319.7	98.0
In-service date	2010 and 2011	2008	1975 and 1978	1969
Property, plant, and equipment	$ 2,431.0	$ 600.5	$ 412.7	$ 45.9
Accumulated depreciation	$ (351.2)	$ (189.2)	$ (127.3)	$ (32.9)
CWIP	$ 9.5	$ 5.3	$ 27.6	$ —

(1) Based on expected capacity ratings for summer 2018. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

(2) Columbia Energy Center (Columbia) is jointly owned by Wisconsin Power and Light (WPL), Madison Gas and Electric (MGE), and WPS. In October 2016, WPL received an order from the PSCW approving amendments to the Columbia joint operating agreement between the parties allowing WPS and MGE to forgo certain capital expenditures at Columbia. As a result, WPL will incur these capital expenditures in exchange for a

proportional increase in its ownership share of Columbia. Based upon the additional capital expenditures WPL expects to incur through June 1, 2020, WPS's ownership interest would decrease to 27.5%.

(3) WPS anticipates that the Edgewater Unit 4 generating unit will be retired by September 30, 2018. See Note 5, Property, Plant, and Equipment, for more information.

NOTE 7—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and polychlorinated biphenyls [PCBs]); asbestos abatement at certain generation and substation facilities, office buildings, and service centers; the removal and dismantlement of generation facilities; the dismantling of wind generation projects; the disposal of PCB-contaminated transformers; the closure of fly-ash landfills at certain generation facilities; and the removal of above ground storage tanks. Regulatory assets and liabilities are established by our utilities to record the differences between ongoing expense recognition under the ARO accounting rules and the rate-making practices for retirement costs authorized by the applicable regulators. AROs have also been recorded by PDL for the removal of solar equipment components. On our balance sheets, AROs are recorded within other long-term liabilities.

The following table shows changes to our AROs during the years ended December 31:

(in millions)	2017	2016	2015
Balance as of January 1	**$ 557.7**	$ 571.2	$ 43.6
Integrys subsidiaries	**—**	—	491.0
Accretion	**27.5**	28.3	14.5
Additions and revisions to estimated cash flows	**26.5** (1)	—	35.5 (2)
Liabilities settled	**(38.0)**	(41.8)	(13.4)
Balance as of December 31	**$ 573.7**	$ 557.7	$ 571.2

(1) AROs increased $20.5 million in 2017 due to revisions made to estimated cash flows primarily for changes in the weighted average cost to retire natural gas distribution pipe at PGL and NSG. In addition, an ARO of $5.5 million was recorded related to the removal and dismantlement of WE's Rothschild Biomass Plant.

(2) During 2015, an ARO of $16.1 million was recorded for fly-ash landfills located at generation facilities owned by WE and WPS. An ARO of $9.0 million was also recorded during 2015 for the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities rule passed by the EPA in April 2015. In addition, AROs increased $10.4 million in 2015 due to revisions made to estimated cash flows primarily for changes in the weighted average cost to retire natural gas distribution pipe at PGL and NSG.

NOTE 8—GOODWILL

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The following table shows changes to our goodwill balances by segment during the years ended December 31, 2017 and 2016:

	Wisconsin		Illinois		Other States		Non-Utility Energy Infrastructure		Total	
(in millions)	2017	2016	2017	2016	2017	2016	2017	2016	2017	2016
Goodwill balance as of January 1	**$ 2,104.3**	$ 2,109.5	**$ 758.7**	$ 731.2	**$ 183.2**	$ 182.8	**$ —**	$ —	**$ 3,046.2**	$ 3,023.5
Adjustment to Integrys purchase price allocation	**—**	(5.2)	**—**	27.5	**—**	0.4	**—**	—	**—**	22.7
Acquisition of Bluewater (1)	**—**	—	**—**	—	**—**	—	**7.3**	—	**7.3**	—
Goodwill balance as of December 31 (2)	**$ 2,104.3**	$ 2,104.3	**$ 758.7**	$ 758.7	**$ 183.2**	$ 183.2	**$ 7.3**	$ —	**$ 3,053.5**	$ 3,046.2

(1) See Note 2, Acquisitions, for more information on the acquisition of Bluewater.

(2) We had no accumulated impairment losses related to our goodwill as of December 31, 2017.

In the third quarter of 2017, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2017. No impairments resulted from these tests.

NOTE 9—COMMON EQUITY

Stock-Based Compensation Plans

The following table summarizes our pre-tax stock-based compensation expense and the related tax benefit recognized in income for the years ended December 31:

(in millions)	**2017**	2016	2015
Stock options	**$ 3.4**	$ 3.5	$ 3.3
Restricted stock	**5.4**	5.8	7.0
Performance units	**20.2**	8.7	13.0
Stock-based compensation expense	**$ 29.0**	$ 18.0	$ 23.3
Related tax benefit	**$ 11.6**	$ 7.2	$ 9.3

Stock-based compensation costs capitalized during 2017, 2016, and 2015 were not significant.

Stock Options

The following is a summary of our stock option activity during 2017:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life *(in years)*	Aggregate Intrinsic Value *(in millions)*
Outstanding as of January 1, 2017	5,122,775	$ 38.95		
Granted	**552,215**	**$ 58.31**		
Exercised	**(1,019,111)**	**$ 30.24**		
Forfeited	**(11,665)**	**$ 56.48**		
Outstanding as of December 31, 2017	**4,644,214**	**$ 43.11**	**6.0**	**$ 108.3**
Exercisable as of December 31, 2017	**3,275,850**	**$ 38.23**	**5.0**	**$ 92.4**

The aggregate intrinsic value of outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they exercised all of their options on December 31, 2017. This is calculated as the difference between our closing stock price on December 31, 2017, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the years ended December 31, 2017, 2016, and 2015 was $33.8 million, $55.4 million, and $36.1 million, respectively. The actual tax benefit from option exercises for the same periods was approximately $13.5 million, $22.2 million, and $14.5 million, respectively.

As of December 31, 2017, approximately $2.7 million of unrecognized compensation cost related to unvested and outstanding stock options was expected to be recognized over the next 1.7 years on a weighted-average basis.

During the first quarter of 2018, the Compensation Committee awarded 660,655 non-qualified stock options with a weighted-average exercise price of $66.02 and a weighted-average grant date fair value of $7.84 per option to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restricted Shares

The following restricted stock activity occurred during 2017:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of January 1, 2017	220,046	$ 51.30
Granted	**82,622**	**$ 58.10**
Released	**(91,147)**	**$ 48.98**
Forfeited	**(7,033)**	**$ 55.60**
Outstanding as of December 31, 2017	**204,488**	**$ 54.94**

The intrinsic value of restricted stock released was $5.4 million, $7.7 million, and $3.7 million for the years ended December 31, 2017, 2016, and 2015, respectively. The actual tax benefit from released restricted shares for the same years was $2.1 million, $3.1 million, and $1.3 million, respectively.

As of December 31, 2017, approximately $4.1 million of unrecognized compensation cost related to restricted stock was expected to be recognized over the next 1.5 years on a weighted-average basis.

During the first quarter of 2018, the Compensation Committee awarded 131,731 restricted shares to certain of our directors, officers, and other key employees under its normal schedule of awarding long-term incentive compensation. The grant date fair value of these awards was $64.97 per share.

Performance Units

During 2017, 2016, and 2015, the Compensation Committee awarded 237,650; 297,305; and 195,365 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $6.7 million, $19.1 million, and $13.2 million were settled during 2017, 2016, and 2015, respectively. The actual tax benefit from the distribution of performance units for the same years was $2.1 million, $6.8 million, and $4.8 million, respectively.

At December 31, 2017, we had 563,033 performance units outstanding, including dividend equivalents. A liability of $27.6 million was recorded on our balance sheet at December 31, 2017 related to these outstanding units. As of December 31, 2017, approximately $23.5 million of unrecognized compensation cost related to unvested and outstanding performance units was expected to be recognized over the next 1.4 years on a weighted-average basis.

During the first quarter of 2018, we settled performance units with an intrinsic value of $7.8 million. The actual tax benefit from the distribution of these awards was $1.7 million. In January 2018, the Compensation Committee also awarded 217,560 performance units to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

Our ability as a holding company to pay common stock dividends primarily depends on the availability of funds received from our utility subsidiaries and our non-utility subsidiary, We Power. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans, or advances. All of our utility subsidiaries, with the exception of UMERC and MGU, are prohibited from loaning funds to us, either directly or indirectly.

In accordance with their most recent rate orders, WE, WG, and WPS may not pay common dividends above the test year forecasted amounts reflected in their respective rate cases, if it would cause their average common equity ratio, on a financial basis, to fall below their authorized levels of 51%, 49.5%, and 51%, respectively. A return of capital in excess of the test year amount can be paid by each company at the end of the year provided that their respective average common equity ratios do not fall below the authorized levels.

WE may not pay common dividends to us under WE's Restated Articles of Incorporation if any dividends on its outstanding preferred stock have not been paid. In addition, pursuant to the terms of WE's 3.60% Serial Preferred Stock, WE's ability to declare common dividends would be limited to 75% or 50% of net income during a twelve month period if its common stock equity to total capitalization, as defined in the preferred stock designation, is less than 25% and 20%, respectively.

NSG's long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of its capital stock.

WEC Energy Group and Integrys have the option to defer interest payments on their junior subordinated notes, from time to time, for one or more periods of up to 10 consecutive years per period. During any period in which they defer interest payments, they may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, their respective common stock.

See Note 11, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to short-term debt obligations.

As of December 31, 2017, restricted net assets of our consolidated subsidiaries totaled approximately $6.3 billion. Our equity in undistributed earnings of investees accounted for by the equity method were approximately $355 million. The total of these amounts exceeds 25% of our consolidated net assets as of December 31, 2017.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

Share Purchases

We have instructed our independent agents to purchase shares on the open market to fulfill obligations under various stock-based employee benefit and compensations plans and to provide shares to participants in our dividend reinvestment and stock purchase plan. As a result, no new shares of common stock were issued in 2017, 2016, or 2015, other than for the Integrys acquisition in 2015. See Note 2, Acquisitions, for more information.

The following is a summary of shares purchased to fulfill exercised stock options and restricted stock awards during the years ended December 31:

(in millions)	2017	2016	2015
Shares purchased	**1.1**	1.8	1.5
Cost of shares purchased	**$ 71.3**	$ 108.0	$ 74.7

Common Stock Dividends

During the year ended December 31, 2017, our Board of Directors declared common stock dividends which are summarized below:

Date Declared	Date Payable	Per Share	Period
January 19, 2017	March 1, 2017	$0.52	First quarter
April 20, 2017	June 1, 2017	$0.52	Second quarter
July 20, 2017	September 1, 2017	$0.52	Third quarter
October 19, 2017	December 1, 2017	$0.52	Fourth quarter

On January 18, 2018, our Board of Directors declared a quarterly cash dividend of $0.5525 per share, which equates to an annual dividend of $2.21 per share. The dividend is payable on March 1, 2018, to shareholders of record on February 14, 2018. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

NOTE 10—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2017 and 2016:

(in millions, except share and per share amounts)	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
WEC Energy Group				
$.01 par value Preferred Stock	**15,000,000**	**—**	**—**	**$ —**
WE				
$100 par value, Six Per Cent. Preferred Stock	**45,000**	**44,498**	**—**	**4.4**
$100 par value, Serial Preferred Stock	**2,286,500**			
3.60% Series		**260,000**	**$ 101**	**26.0**
$25 par value, Serial Preferred Stock	**5,000,000**	**—**	**—**	**—**
WPS				
$100 par value, Preferred Stock	**1,000,000**	**—**	**—**	**—**
PGL				
$100 par value, Cumulative Preferred Stock	**430,000**	**—**	**—**	**—**
NSG				
$100 par value, Cumulative Preferred Stock	**160,000**	**—**	**—**	**—**
Total				**$ 30.4**

NOTE 11—SHORT-TERM DEBT AND LINES OF CREDIT

The following table shows our short-term borrowings and their corresponding weighted-average interest rates as of December 31:

(in millions, except percentages)	2017	2016
Commercial paper		
Amount outstanding at December 31	**$ 1,444.6**	$ 860.2
Average interest rate on amounts outstanding at December 31	**1.77%**	0.96%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2017, was $833.8 million with a weighted-average interest rate during the period of 1.34%.

WEC Energy Group, WE, WPS, WG, and PGL have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, require them to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 70.0%, 65.0%, 65.0%, 65.0%, and 65.0%, respectively. As of December 31, 2017, all companies were in compliance with their respective ratio.

As of December 31, 2017, we had $1,347.5 million of available capacity under our bank back-up credit facilities and $1,444.6 million of commercial paper outstanding that was supported by the credit facilities.

The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing program, including remaining available capacity under these facilities as of December 31:

(in millions)	Maturity	2017
WEC Energy Group	October 2022	**$ 1,200.0**
WE	October 2022	**500.0**
WPS *	December 2020	**400.0**
WG	October 2022	**350.0**
PGL	October 2022	**350.0**
Total short-term credit capacity		**$ 2,800.0**
Less:		
Letters of credit issued inside credit facilities		**$ 7.9**
Commercial paper outstanding		**1,444.6**
Available capacity under existing agreements		**$ 1,347.5**

* In February 2018, WPS received approval from the PSCW to extend the maturity of its facility to October 2022.

Each of these facilities has a renewal provision for two one-year extensions, subject to lender approval.

The bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, Employee Retirement Income Security Act of 1974 defaults, and change of control. In addition, pursuant to the terms of our credit agreement, we must ensure that certain of our subsidiaries comply with several of the covenants contained therein.

NOTE 12—LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

See our statements of capitalization for details on our long-term debt.

WEC Energy Group, Inc.

Effective May 2017, the $500.0 million of 2007 Junior Notes bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 211.25 basis points, and reset quarterly.

Wisconsin Public Service Corporation

In November 2017, WPS's $125.0 million of 5.65% Senior Notes matured, and the outstanding principal was repaid with proceeds WPS received from selling commercial paper.

Minnesota Energy Resources Corporation

In June 2017, MERC issued $120.0 million of senior notes. The senior notes were issued in three tranches: $40.0 million of 3.11% Senior Notes due July 15, 2027; $40.0 million of 3.41% Senior Notes due July 15, 2032; and $40.0 million of 4.01% Senior Notes due July 15, 2047. Net proceeds were used to repay MERC's $78.0 million aggregate long-term debt obligation to its parent, Integrys. Remaining proceeds were used for general corporate purposes, including repayment of short-term debt borrowed from Integrys.

Michigan Gas Utilities Corporation

In June 2017, MGU issued $90.0 million of senior notes. The senior notes were issued in three tranches: $30.0 million of 3.11% Senior Notes due July 15, 2027; $30.0 million of 3.41% Senior Notes due July 15, 2032; and $30.0 million of 4.01% Senior Notes due July 15, 2047. Net proceeds were used to repay MGU's $71.0 million aggregate long-term debt obligation to its parent, Integrys. Remaining proceeds were used for general corporate purposes, including repayment of short-term debt borrowed from Integrys.

The Peoples Gas Light and Coke Company

In November 2017, PGL issued $100.0 million of 3.77% Series EEE Bonds due December 1, 2047. The net proceeds were used for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

Bluewater Gas Storage, LLC

In December 2017, Bluewater Gas Storage, LLC, (BGS), a subsidiary of Bluewater, issued $125.0 million of 3.76% Senior Notes due December 20, 2047. The net proceeds were used to redeem all intercompany debt from WEC Energy Group and for other limited liability company purposes. BGS's long-term debt amortizes on a mortgage-style basis.

During 2018, $2.3 million of BGS's outstanding $125.0 million of 3.76% senior notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

W.E. Power, LLC

All of We Power's outstanding long-term debt amortizes on a mortgage-style basis.

During 2018, $5.9 million of We Power's outstanding $101.0 million of 4.91% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

During 2018, $4.9 million of We Power's outstanding $121.5 million of 6.00% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

During 2018, $11.4 million of We Power's outstanding $194.1 million of 5.209% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

During 2018, $8.9 million of We Power's outstanding $162.4 million of 4.673% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

Bonds and Notes

The following table shows the future maturities of our long-term debt outstanding (excluding obligations under capital leases) as of December 31, 2017:

(in millions)	**Payments**
2018	$ 838.4
2019	360.1
2020	686.9
2021	338.8
2022	40.7
Thereafter	7,336.0
Total	$ 9,600.9

We amortize debt premiums, discounts, and debt issuance costs over the life of the debt and we include the costs in interest expense.

As of December 31, 2017, WE was the obligor under a series of tax-exempt pollution control refunding bonds with an outstanding principal amount of $80.0 million. In August 2009, WE terminated a letter of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. WE purchased the bonds at par plus accrued interest to the date of purchase. As of December 31, 2017, the repurchased bonds were still outstanding, but were not reported in our long-term debt since they were held by WE. Depending on market conditions and other factors, WE may change the method used to determine the interest rate on this bond series and have it remarketed to third parties. A related bond series that had an outstanding principal amount of $67.0 million matured on August 1, 2016.

In connection with our outstanding 2007 Junior Notes, we executed a Replacement Capital Covenant dated May 11, 2007 (RCC), which we amended on June 29, 2015, for the benefit of persons that buy, hold, or sell a specified series of our long-term indebtedness (covered debt). Our 6.20% Senior Notes due April 1, 2033 have been designated as the covered debt under the RCC. The RCC provides that we may not redeem, defease, or purchase, and that our subsidiaries may not purchase, any 2007 Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, we have received a specified amount of proceeds from the sale of qualifying securities.

In connection with Integrys's outstanding 2006 Junior Notes, Integrys executed a Replacement Capital Covenant dated December 1, 2006, as replaced by a new Replacement Capital Covenant on December 1, 2010 (Integrys RCC) for the benefit of persons that buy, hold, or sell a specified series of its long-term indebtedness (covered debt). Integrys's 4.17% Senior Notes due November 1, 2020, have been designated as the covered debt under the Integrys RCC. The Integrys RCC provides that Integrys may not redeem, defease, or purchase, and that its subsidiaries may not purchase, any 2006 Junior Notes on or before December 1, 2036, unless, subject to certain limitations described in the Integrys RCC, Integrys has received a specified amount of proceeds from the sale of qualifying securities.

Effective August 2023, Integrys's $400.0 million of 2013 6.00% Junior Subordinated Notes due 2073 will bear interest at the three-month LIBOR plus 322 basis points and will reset quarterly.

Certain long-term debt obligations contain financial and other covenants. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

Obligations Under Capital Leases

In 1997, WE entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MW of firm capacity from a natural gas-fired cogeneration facility, includes zero minimum energy requirements. When the contract expires in 2022, WE may, at its option and with proper notice, renew for another 10 years or purchase the generating facility at fair value or allow the contract to expire. We account for this contract as a capital lease and recorded the leased facility and corresponding obligation under the capital lease at the estimated fair value of the plant's electric generating facilities. We are amortizing the leased facility on a straight-line basis over the original 25-year term of the contract.

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as cost of sales on our income statements. We paid a total of $7.2 million and $37.6 million in lease payments during 2017 and 2016, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our balance sheets. Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to approximately $78.5 million during 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $27.0 million as of December 31, 2017, and will decrease to zero over the remaining life of the contract.

The following is a summary of our capitalized leased facilities as of December 31:

(in millions)	2017	2016
Long-term power purchase commitment	**$ 140.3**	$ 140.3
Accumulated amortization	**(115.2)**	(109.5)
Total leased facilities	**$ 25.1**	$ 30.8

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2017 are as follows:

(in millions)	Payments
2018	$ 14.7
2019	15.5
2020	16.4
2021	17.2
2022	7.6
Thereafter	—
Total minimum lease payments	71.4
Less: Estimated executory costs	(33.1)
Net minimum lease payments	38.3
Less: Interest	(11.3)
Present value of net minimum lease payments	27.0
Less: Due currently	(3.7)
Long-term obligations under capital lease	**$ 23.3**

NOTE 13—INCOME TAXES

Income Tax Expense

The following table is a summary of income tax expense for the years ended December 31:

(in millions)	2017	2016	2015
Current tax expense	**$ 111.8**	$ 72.7	$ 15.1
Deferred income taxes, net	**274.4**	498.7	420.4
Investment tax credit, net	**(2.7)**	(4.9)	(1.7)
Total income tax expense	**$ 383.5**	$ 566.5	$ 433.8

Statutory Rate Reconciliation

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable United States statutory federal income tax rate to income before income taxes as a result of the following:

	2017		2016		2015	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 555.5**	**35.0 %**	$ 526.4	35.0 %	$ 375.5	35.0 %
State income taxes net of federal tax benefit	**100.8**	**6.4 %**	72.8	4.8 %	73.1	6.8 %
Federal tax reform	**(226.9)**	**(14.3)%**	—	— %	—	— %
Production tax credits	**(16.8)**	**(1.1)%**	(15.7)	(1.1)%	(17.4)	(1.6)%
AFUDC – Equity	**(4.0)**	**(0.3)%**	(8.8)	(0.6)%	(7.1)	(0.7)%
Investment tax credit restored	**(2.7)**	**(0.2)%**	(4.9)	(0.3)%	(1.7)	(0.2)%
Other, net	**(22.4)**	**(1.4)%**	(3.3)	(0.2)%	11.4	1.1 %
Total income tax expense	**$ 383.5**	**24.1 %**	$ 566.5	37.6 %	$ 433.8	40.4 %

The net impact of tax reform in the amount of $206.7 million is represented in both the Federal tax reform and State income taxes net of federal tax benefit lines above.

Deferred Income Tax Assets and Liabilities

On December 22, 2017, the Tax Legislation was signed into law. For businesses, the Tax Legislation reduces the corporate federal tax rate from a maximum of 35% to a 21% rate effective January 1, 2018. We estimated a preliminary tax benefit related to the re-measurement of our deferred taxes in the amount of approximately $2,657 million. Accordingly, the tax benefit related to our regulated utilities was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets as of December 31, 2017. The effects of federal Tax Legislation primarily at our non-utility energy infrastructure and corporate and other segments resulted in the recording of an income tax benefit of approximately $206.7 million for the year ended December 31, 2017. This tax benefit is primarily due to a re-measurement of deferred tax assets and liabilities. Our revaluation of our deferred tax assets and liabilities is subject to further clarification of the new law that cannot be estimated at this time. The impact of the Tax Legislation could materially differ from this estimate due to, among other things, changes in interpretations and assumptions we have made.

On December 22, 2017, the SEC staff issued guidance in Staff Accounting Bulletin 118 (SAB 118), Income Tax Accounting Implications of the Tax Cuts and Jobs Act, which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, certain amounts related to bonus depreciation and future tax benefit utilization recorded in the financial statements as a result of the Tax Legislation are to be considered "provisional" as discussed in SAB 118 and subject to revision. We are awaiting additional guidance from industry and income tax authorities in order to finalize our accounting.

The components of deferred income taxes as of December 31 are as follows:

(in millions)	2017	2016
Deferred tax assets		
Tax gross up – regulatory items	**$ 585.8**	$ —
Future tax benefits	**303.9**	430.4
Employee benefits and compensation	**164.2**	222.0
Deferred revenues	**128.8**	207.2
Property-related	**24.4**	54.5
Other	**185.0**	230.6
Total deferred tax assets	**1,392.1**	1,144.7
Valuation allowance	**(15.7)**	(15.0)
Net deferred tax assets	**$ 1,376.4**	$ 1,129.7
Deferred tax liabilities		
Property-related	**$ 3,464.6**	$ 4,979.3
Investment in transmission affiliate	**321.2**	476.9
Employee benefits and compensation	**285.8**	401.6
Deferred transmission costs	**60.1**	93.1
Other	**244.5**	325.4
Total deferred tax liabilities	**4,376.2**	6,276.3
Deferred tax liability, net	**$ 2,999.8**	$ 5,146.6

Consistent with rate-making treatment, deferred taxes related to our regulated utilities in the table above are offset for temporary differences that have related regulatory assets and liabilities.

The components of net deferred tax assets associated with federal and state tax benefit carryforwards as of December 31, 2017 and 2016 are summarized in the tables below:

2017 ***(in millions)***	**Gross Value**	**Deferred Tax Effect**	**Valuation Allowance**	**Earliest Year of Expiration**
Future tax benefits as of December 31, 2017				
Federal foreign tax credit	**$ —**	**$ 13.5**	**$ (13.5)**	**2018**
Other federal tax credit	**—**	**259.6**	**(0.1)**	**2025**
Charitable contribution and capital loss	**21.7**	**8.6**	**(2.1)**	**2017**
State net operating loss	**282.7**	**17.2**	**—**	**2025**
State tax credit	**—**	**5.0**	**—**	**2017**
Balance as of December 31, 2017	**$ 304.4**	**$ 303.9**	**$ (15.7)**	

2016 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2016				
Federal net operating loss	$ 407.6	$ 142.7	$ —	2031
Federal foreign tax credit	—	13.5	(13.5)	2017
Other federal tax credit	—	241.1	—	2025
Charitable contribution	9.4	4.0	(1.5)	2016
State net operating loss	482.6	24.3	—	2024
State tax credit	—	4.8	—	2016
Balance as of December 31, 2016	$ 899.6	$ 430.4	$ (15.0)	

Valuation allowances of $15.7 million have been established for certain tax benefit carryforwards obtained in the Integrys acquisition based on our projected ability to realize such benefits by offsetting future tax liabilities. This is primarily the result of bonus depreciation. Realization is dependent on generating sufficient tax liabilities prior to expiration of the tax benefit carryforwards.

Unrecognized Tax Benefits

We previously adopted accounting guidance related to uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(in millions)	2017	2016
Balance as of January 1	**$ 14.5**	$ 9.5
Additions for tax positions of prior years	**7.9**	6.7
Additions based on tax positions related to the current year	**0.5**	1.1
Reductions for tax positions of prior years	**(5.6)**	(1.0)
Reductions due to statute of limitations	**—**	(1.8)
Balance as of December 31	**$ 17.3**	$ 14.5

The amount of unrecognized tax benefits as of December 31, 2017 and 2016, excludes deferred tax assets related to uncertainty in income taxes of $2.1 million and $6.6 million, respectively. As of December 31, 2017 and 2016, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $15.2 million and $7.9 million, respectively.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the years ended December 31, 2017, 2016, and 2015, we recognized $0.6 million of interest income, $0.2 million of interest expense, and zero interest, respectively, in our income statements. For the years ended December 31, 2017, 2016, and 2015, we recognized no penalties in our income statements. For the year ended December 31, 2017, we had $0.2 million of interest accrued and no penalties accrued on our balance sheets. For the year ended December 31, 2016, we had $0.8 million of interest accrued and no penalties accrued on our balance sheets.

We do not anticipate any significant increases or decreases in the total amounts of unrecognized tax benefits within the next 12 months.

We file income tax returns in the United States federal jurisdiction and state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. As of December 31, 2017, we were subject to examination by state or local tax authorities for the 2013 through 2017 tax years in our major state operating jurisdictions as follows:

Jurisdiction	Years
Federal	2014–2017
Illinois	2013–2017
Michigan	2013–2017
Minnesota	2014–2017
Wisconsin	2013–2017

NOTE 14—FAIR VALUE MEASUREMENTS

The following tables summarize our financial assets and liabilities that were accounted for at fair value on a recurring basis, categorized by level within the fair value hierarchy:

	December 31, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 1.8	$ 3.9	$ —	$ 5.7
Petroleum products contracts	1.2	—	—	1.2
FTRs	—	—	4.4	4.4
Coal contracts	—	1.1	—	1.1
Total derivative assets	$ 3.0	$ 5.0	$ 4.4	$ 12.4
Investments held in rabbi trust	$ 120.7	$ —	$ —	$ 120.7
Derivative liabilities				
Natural gas contracts	$ 7.0	$ 3.8	$ —	$ 10.8
Coal contracts	—	0.8	—	0.8
Total derivative liabilities	$ 7.0	$ 4.6	$ —	$ 11.6

	December 31, 2016			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 10.1	$ 24.2	$ —	$ 34.3
Petroleum products contracts	0.2	—	—	0.2
FTRs	—	—	5.1	5.1
Coal contracts	—	2.0	—	2.0
Total derivative assets	$ 10.3	$ 26.2	$ 5.1	$ 41.6
Investments held in rabbi trust	$ 103.9	$ —	$ —	$ 103.9
Derivative liabilities				
Natural gas contracts	$ 0.2	$ 0.2	$ —	$ 0.4
Petroleum products contracts	0.1	—	—	0.1
Coal contracts	—	1.9	—	1.9
Total derivative liabilities	$ 0.3	$ 2.1	$ —	$ 2.4

The derivative assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy Markets. See Note 15, Derivative Instruments, for more information.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy at December 31:

(in millions)	2017	2016	2015
Balance at the beginning of the period	$ 5.1	$ 3.6	$ 7.0
Realized and unrealized (losses) gains	—	(0.2)	1.3
Purchases	13.8	15.2	3.9
Sales	—	(0.2)	(0.1)
Settlements	(14.5)	(13.3)	(11.9)
Acquisition of Integrys	—	—	(1.3)
Transfers out of level 3	—	—	4.7
Balance at the end of the period	$ 4.4	$ 5.1	$ 3.6

Unrealized gains and losses on Level 3 derivatives are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through cost of sales on the income statements.

Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value at December 31:

	2017		2016	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock	**$ 30.4**	**$ 30.5**	$ 30.4	$ 28.8
Long-term debt, including current portion *	**9,561.7**	**10,341.9**	9,285.8	9,818.2

* The carrying amount of long-term debt excludes capital lease obligations of $27.0 million and $29.6 million at December 31, 2017 and December 31, 2016, respectively.

NOTE 15—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities:

	December 31, 2017		December 31, 2016	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 5.6**	**$ 9.4**	$ 31.4	$ 0.4
Petroleum products contracts	**1.2**	**—**	0.2	0.1
FTRs	**4.4**	**—**	5.1	—
Coal contracts	**0.6**	**0.6**	1.5	1.4
Total other current	**$ 11.8**	**$ 10.0**	$ 38.2	$ 1.9
Other long-term				
Natural gas contracts	**$ 0.1**	**$ 1.4**	$ 2.9	$ —
Coal contracts	**0.5**	**0.2**	0.5	0.5
Total other long-term	**$ 0.6**	**$ 1.6**	$ 3.4	$ 0.5
Total	**$ 12.4**	**$ 11.6**	$ 41.6	$ 2.4

Our estimated notional sales volumes and realized gains (losses) were as follows for the years ended:

	December 31, 2017		December 31, 2016		December 31, 2015	
(in millions)	Volume	Gains (Losses)	Volume	Gains (Losses)	Volume	Gains (losses)
Natural gas contracts	123.1 Dth	**$ (8.0)**	151.1 Dth	$ (59.6)	86.2 Dth	$ (50.5)
Petroleum products contracts	18.0 gallons	**(1.3)**	14.7 gallons	(3.2)	7.8 gallons	(1.9)
FTRs	36.2 MWh	**14.0**	33.7 MWh	13.3	27.3 MWh	6.7
Total		**$ 4.7**		$ (49.5)		$ (45.7)

The following table shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on our balance sheets:

	December 31, 2017		December 31, 2016	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 12.4**	**$ 11.6**	$ 41.6	$ 2.4
Gross amount not offset on the balance sheet	**(4.9)**	**(9.0)** (1)	(4.9) (2)	(0.5)
Net amount	**$ 7.5**	**$ 2.6**	$ 36.7	$ 1.9

(1) Includes cash collateral posted of $4.1 million.

(2) Includes cash collateral received of $4.4 million.

At December 31, 2017 and 2016, we had posted cash collateral of $16.2 million and $16.4 million, respectively, in our margin accounts. At December 31, 2016, we had also received cash collateral of $4.4 million in our margin accounts. Certain of our derivative and non-derivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a net liability position at December 31, 2017 and 2016 was $3.7 million and $0.2 million, respectively. At December 31, 2017 and 2016, we had not posted any cash collateral related to the credit risk-related contingent features of these commodity instruments. If all of the credit risk-related contingent features contained in derivative instruments in a net liability position had been triggered at December 31, 2017, we would have been required to post collateral of $2.7 million. At December 31, 2016, we would not have been required to post any collateral.

During 2015, we settled several forward interest rate swap agreements entered into to mitigate interest rate risk associated with the issuance of $1.2 billion of long-term debt related to the acquisition of Integrys. As these agreements qualified for cash flow hedge accounting treatment, the proceeds of $19.0 million received upon settlement were deferred in accumulated other comprehensive income and are being amortized as a decrease to interest expense over the periods in which the interest costs are recognized in earnings.

For the years ended December 31, 2017, 2016, and 2015, we reclassified $2.2 million, $2.2 million, and $1.2 million, respectively, of forward interest rate swap agreement settlements deferred in accumulated other comprehensive income as a reduction to interest expense. We estimate that during the next twelve months, $2.2 million will be reclassified from accumulated other comprehensive income as a reduction to interest expense.

NOTE 16—GUARANTEES

The following table shows our outstanding guarantees:

(in millions)	Total Amounts Committed at December 31, 2017	Expiration: Less Than 1 Year	Expiration: 1 to 3 Years	Expiration: Over 3 Years
Guarantees				
Guarantees supporting commodity transactions of subsidiaries [1]	**$ 8.1**	$ 8.1	$ —	$ —
Standby letters of credit [2]	**55.1**	54.7	0.4	—
Surety bonds [3]	**9.7**	9.7	—	—
Other guarantees [4]	**10.9**	0.5	—	10.4
Total guarantees	**$ 83.8**	$ 73.0	$ 0.4	$ 10.4

(1) Consists of $8.1 million to support the business operations of Bluewater.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts are not reflected on our balance sheets.

(3) Primarily for workers compensation self-insurance programs and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(4) Consists of $10.9 million related to other indemnifications, for which a liability of $10.4 million related to workers compensation coverage was recorded on our balance sheets.

NOTE 17—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

We and our subsidiaries have defined benefit pension plans that cover substantially all of our employees, as well as several unfunded non-qualified retirement plans. In addition, we and our subsidiaries offer multiple OPEB plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. We also offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

Generally, former Wisconsin Energy Corporation employees who started with the company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. New Wisconsin Energy Corporation management employees hired after December 31, 2014 receive a 6% annual company contribution to their 401(k) savings plan instead of being enrolled in the defined benefit plans.

For former Integrys employees, the defined benefit pension plans are closed to all new hires. In addition, the service accruals for the defined benefit pension plans were frozen for non-union employees as of January 1, 2013. These employees receive an annual company contribution to their 401(k) savings plan, which is calculated based on age, wages, and full years of vesting service as of December 31 each year.

We use a year-end measurement date to measure the funded status of all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following tables provide a reconciliation of the changes in our plans' benefit obligations and fair value of assets:

	Pension Costs				OPEB Costs			
(in millions)	2017		2016		2017		2016	
Change in benefit obligation								
Obligation at January 1	**$**	**3,058.8**	$	3,083.0	**$**	**818.4**	$	842.0
Service cost		**44.6**		45.4		**24.1**		26.1
Interest cost		**121.8**		130.8		**32.9**		37.0
Participant contributions		**—**		—		**13.4**		16.4
Plan amendments		**—**		(3.0)		**(36.4)**		(18.9)
Actuarial loss (gain)		**162.6**		71.7		**12.9**		(36.5)
Benefit payments		**(224.1)**		(269.1)		**(48.8)**		(49.1)
Federal subsidy on benefits paid		**N/A**		N/A		**2.0**		1.4
Obligation at December 31	**$**	**3,163.7**	$	3,058.8	**$**	**818.5**	$	818.4
Change in fair value of plan assets								
Fair value at January 1	**$**	**2,709.2**	$	2,755.1	**$**	**773.5**	$	749.8
Actual return on plan assets		**368.7**		199.4		**95.9**		51.5
Employer contributions		**113.0**		23.8		**7.5**		4.9
Participant contributions		**—**		—		**13.4**		16.4
Benefit payments		**(224.1)**		(269.1)		**(48.8)**		(49.1)
Fair value at December 31	**$**	**2,966.8**	$	2,709.2	**$**	**841.5**	$	773.5
Funded status at December 31	**$**	**(196.9)**	$	(349.6)	**$**	**23.0**	$	(44.9)

The amounts recognized on our balance sheets at December 31 related to the funded status of the benefit plans were as follows:

	Pension Costs				OPEB Costs			
(in millions)	2017		2016		2017		2016	
Other long-term assets	**$**	**143.0**	$	74.4	**$**	**80.5**	$	29.7
Pension and OPEB obligations		**339.9**		424.0		**57.5**		74.6
Total net (liabilities) assets	**$**	**(196.9)**	$	(349.6)	**$**	**23.0**	$	(44.9)

The accumulated benefit obligation for all defined benefit pension plans was $3,057.7 million and $2,939.9 million as of December 31, 2017 and 2016, respectively.

The following table shows information for pension plans with an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2017		2016	
Projected benefit obligation	**$**	**679.5**	$	1,667.0
Accumulated benefit obligation		**630.3**		1,549.5
Fair value of plan assets		**339.6**		1,242.9

The following table shows the amounts that have not yet been recognized in our net periodic benefit cost as of December 31:

	Pension Costs				OPEB Costs			
(in millions)	2017		2016		2017		2016	
Accumulated other comprehensive loss (pre-tax) (1)								
Net actuarial loss (gain)	**$**	**10.0**	$	12.0	**$**	**(1.0)**	$	(1.0)
Prior service credits		**—**		—		**(0.1)**		—
Total	**$**	**10.0**	$	12.0	**$**	**(1.1)**	$	(1.0)
Net regulatory assets (2)								
Net actuarial loss (gain)	**$**	**1,136.8**	$	1,240.7	**$**	**(4.7)**	$	25.8
Prior service costs (credits)		**7.5**		10.5		**(111.8)**		(87.9)
Total	**$**	**1,144.3**	$	1,251.2	**$**	**(116.5)**	$	(62.1)

(1) Amounts related to the nonregulated entities are included in accumulated other comprehensive loss.

(2) Amounts related to the utilities and WBS are recorded as net regulatory assets or liabilities.

The following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2018:

(in millions)	Pension Costs	OPEB Costs
Net actuarial loss	$ 92.5	$ 1.3
Prior service costs (credits)	2.6	(15.3)
Total 2018 – estimated amortization	$ 95.1	$ (14.0)

The components of net periodic benefit cost (including amounts capitalized to our balance sheets) for the years ended December 31 were as follows:

	Pension Costs			OPEB Costs		
(in millions)	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Service cost	**$ 44.6**	$ 45.4	$ 30.4	**$ 24.1**	$ 26.1	$ 20.7
Interest cost	**121.8**	130.8	94.3	**32.9**	37.0	26.7
Expected return on plan assets	**(195.7)**	(195.9)	(155.6)	**(55.5)**	(52.7)	(39.6)
Plan settlement	**9.0**	16.5	—	**—**	—	—
Plan curtailment	**—**	—	(0.3)	**—**	—	—
Amortization of prior service cost (credit)	**2.9**	3.4	2.2	**(12.3)**	(9.4)	(6.4)
Amortization of net actuarial loss	**86.1**	82.9	68.5	**3.1**	8.5	3.9
Net periodic benefit cost (credit)	**$ 68.7**	$ 83.1	$ 39.5	**$ (7.7)**	$ 9.5	$ 5.3

The weighted-average assumptions used to determine the benefit obligations for the plans were as follows for the years ended December 31:

	Pension		OPEB	
	2017	**2016**	**2017**	**2016**
Discount rate	**3.66%**	4.16%	**3.63%**	4.14%
Rate of compensation increase	**3.61%**	3.60%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**6.50%**	7.00%
Ultimate trend rate (Pre 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Pre 65)	**N/A**	N/A	**2024**	2021
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**6.09%**	7.00%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2028**	2021

The weighted-average assumptions used to determine the net periodic benefit cost for the plans were as follows for the years ended December 31:

	Pension Costs		
	2017	**2016**	**2015**
Discount rate	**4.11%**	4.35%	4.11%
Expected return on plan assets	**7.11%**	7.12%	7.37%
Rate of compensation increase	**3.60%**	3.75%	4.00%

	OPEB Costs		
	2017	**2016**	**2015**
Discount rate	**4.04%**	4.38%	4.09%
Expected return on plan assets	**7.25%**	7.25%	7.54%
Assumed medical cost trend rate (Pre 65/Post 65)	**7.00%**	7.50%	7.50%
Ultimate trend rate	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached	**2021**	2021	2021

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund. For 2018, the expected return on assets assumption is 7.12% for the pension plans and 7.25% for the OPEB plans.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for health care plans. For the year ended December 31, 2017, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

(in millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 8.0	$ (6.4)
Effect on health care component of the accumulated postretirement benefit obligations	76.2	(62.5)

Plan Assets

Current pension trust assets and amounts which are expected to be contributed to the trusts in the future are expected to be adequate to meet pension payment obligations to current and future retirees.

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

The legacy Wisconsin Energy Corporation pension trust target asset allocations are 35% equity investments, 55% fixed income investments, and 10% private equity and real estate investments. The legacy Integrys pension trust target asset allocation is 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. The legacy Wisconsin Energy Corporation OPEB trusts' target asset allocations are 60% equity investments and 40% fixed income investments. The two largest legacy OPEB trusts for Integrys have target asset allocations of 45% equity investments and 55% fixed income, and 50% equity investments and 50% fixed income, respectively. Equity securities include investments in large-cap, mid-cap, and small-cap companies primarily located in the United States. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and United States Treasuries.

Pension and OPEB plan investments are recorded at fair value. See Note 1(p), Fair Value Measurements, for more information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used.

The following tables provide the fair values of our investments by asset class:

	December 31, 2017							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	**$ —**	**$ 53.6**	**$ —**	**$ 53.6**	**$ 19.6**	**$ 2.3**	**$ —**	**$ 21.9**
Equity securities:								
United States Equity	**345.0**	**0.1**	**—**	**345.1**	**101.0**	**—**	**—**	**101.0**
International Equity	**352.1**	**—**	**0.8**	**352.9**	**115.3**	**—**	**0.2**	**115.5**
Fixed income securities: *								
United States Bonds	**138.6**	**892.9**	**—**	**1,031.5**	**121.0**	**148.1**	**—**	**269.1**
International Bonds	**17.8**	**86.8**	**—**	**104.6**	**7.2**	**9.1**	**—**	**16.3**
Private Equity and Real Estate	**—**	**154.1**	**100.1**	**254.2**	**—**	**6.6**	**7.7**	**14.3**
	$ 853.5	**$ 1,187.5**	**$ 100.9**	**$ 2,141.9**	**$ 364.1**	**$ 166.1**	**$ 7.9**	**$ 538.1**
Investments measured at net asset value				**$ 824.9**				**$ 303.4**
Total	**$ 853.5**	**$ 1,187.5**	**$ 100.9**	**$ 2,966.8**	**$ 364.1**	**$ 166.1**	**$ 7.9**	**$ 841.5**

* This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

	December 31, 2016															
	Pension Plan Assets								OPEB Assets							
(in millions)	Level 1		Level 2		Level 3		Total		Level 1		Level 2		Level 3		Total	
Asset Class																
Cash and cash equivalents	$	3.7	$	58.0	$	—	$	61.7	$	28.8	$	3.4	$	—	$	32.2
Equity securities:																
United States Equity		273.9		0.1		—		274.0		34.3		—		—		34.3
International Equity		54.1		0.6		—		54.7		3.5		0.2		—		3.7
Fixed income securities: *																
United States Bonds		—		861.3		0.8		862.1		—		137.9		—		137.9
International Bonds		—		75.9		—		75.9		—		8.8		—		8.8
Private Equity and Real Estate		—		—		14.6		14.6		—		—		1.3		1.3
	$	331.7	$	995.9	$	15.4	$	1,343.0	$	66.6	$	150.3	$	1.3	$	218.2
Investments measured at net asset value							$	1,366.2							$	555.3
Total	$	331.7	$	995.9	$	15.4	$	2,709.2	$	66.6	$	150.3	$	1.3	$	773.5

* This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

The following tables set forth a reconciliation of changes in the fair value of pension and OPEB plan assets categorized as Level 3 in the fair value hierarchy:

	Private Equity and Real Estate				International Equity				U.S. Bonds	
(in millions)	Pension		OPEB		Pension		OPEB		Pension	
Beginning balance at January 1, 2017	**$**	**14.6**	**$**	**1.3**	**$**	**—**	**$**	**—**	**$**	**0.8**
Realized and unrealized gains (losses)		**2.8**		**0.3**		**(0.2)**		**—**		**(0.8)**
Purchases		**55.5**		**3.6**		**1.0**		**0.2**		**—**
Transfers into level 3		**27.2**		**2.5**		**—**		**—**		**—**
Ending balance at December 31, 2017	**$**	**100.1**	**$**	**7.7**	**$**	**0.8**	**$**	**0.2**	**$**	**—**

	Private Equity and Real Estate				U.S. Bonds	
(in millions)	Pension		OPEB		Pension	
Beginning balance at January 1, 2016	$	5.5	$	0.4	$	—
Realized and unrealized gains		0.5		0.1		—
Purchases		8.6		0.8		0.8
Ending balance at December 31, 2016	$	14.6	$	1.3	$	0.8

Cash Flows

We expect to contribute $12.2 million to the pension plans and $0.9 million to the OPEB plans in 2018, dependent upon various factors affecting us, including our liquidity position and the effects of the new Tax Legislation.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and OPEB:

(in millions)	Pension Costs		OPEB Costs	
2018	$	234.3	$	44.2
2019		233.4		46.3
2020		236.3		46.6
2021		233.4		48.1
2022		220.3		49.4
2023-2027		1,026.8		258.2

Savings Plans

We sponsor 401(k) savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. Certain employees participate in a defined contribution pension plan, in which amounts are contributed to the employee's savings plan account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans were $47.9 million, $44.3 million, and $48.0 million in 2017, 2016, and 2015, respectively.

NOTE 18—INVESTMENT IN TRANSMISSION AFFILIATES

We own approximately 60% of ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects. We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. The corporate managers for ATC and ATC Holdco each have an eleven-member board of directors. We have one representative on each board. Each member of the board has only one vote. Due to voting requirements, each individual board member has less than 10% of the voting control. The following tables provide a reconciliation of the changes in our investments in ATC and ATC Holdco:

	2017		
(in millions)	**ATC**	**ATC Holdco**	**Total**
Balance at January 1	**$ 1,443.9**	**$ —**	**$ 1,443.9**
Add: Earnings (loss) from equity method investment	**166.0**	**(11.7)**	**154.3**
Add: Capital contributions	**60.3**	**49.3**	**109.6**
Less: Distributions	**154.2** *	**—**	**154.2**
Less: Other	**0.2**	**—**	**0.2**
Balance at December 31	**$ 1,515.8**	**$ 37.6**	**$ 1,553.4**

* Of this amount, $39.9 million was recorded as a receivable from ATC in other current assets at December 31, 2017.

	ATC	
(in millions)	**2016**	**2015**
Balance at January 1	$ 1,380.9	$ 424.1
Add: Earnings from equity method investment	146.5	96.1
Add: Capital contributions	42.3	8.7
Add: Acquisition of Integrys's investment in ATC	(1.0)	541.5
Add: Equity method goodwill from the acquisition of Integrys (1)	10.4	395.8
Less: Distributions	135.1 (2)	85.1
Less: Other	0.1	0.2
Balance at December 31	$ 1,443.9	$ 1,380.9

(1) Represents the purchase price allocated to Integrys's investment in ATC in excess of the recorded value.

(2) Of this amount, $35.2 million was recorded as a receivable from ATC in other current assets at December 31, 2016.

We pay ATC for network transmission and other related services it provides. In addition, we provide a variety of operational, maintenance, and project management work for ATC, which is reimbursed by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while the projects are under construction. ATC reimburses us for these costs when the new generation is placed in service.

The following table summarizes our significant related party transactions with ATC during the years ended December 31:

(in millions)	**2017**	**2016**	**2015**
Charges to ATC for services and construction	**$ 17.1**	$ 18.5	$ 15.4
Charges from ATC for network transmission services	**349.3**	357.3	289.2
Refund from ATC per FERC ROE order	**(28.3)**	—	—

As of December 31, 2017 and 2016, our balance sheets included the following receivables and payables related to ATC:

(in millions)	**2017**	**2016**
Accounts receivable		
Services provided to ATC	**$ 1.5**	$ 2.2
Other current assets		
Dividends receivable from ATC	**39.9**	35.2
Accounts payable		
Services received from ATC	**31.2**	28.7

Summarized financial data for ATC is included in the tables below:

(in millions)	2017	2016	2015
Income statement data			
Revenues	**$ 721.7**	$ 650.8	$ 615.8
Operating expenses	**345.0**	322.5	319.3
Other expense	**104.1**	95.5	96.1
Net income	**$ 272.6**	$ 232.8	$ 200.4

(in millions)	December 31, 2017	December 31, 2016
Balance sheet data		
Current assets	**$ 87.7**	$ 75.8
Noncurrent assets	**4,598.9**	4,312.9
Total assets	**$ 4,686.6**	$ 4,388.7
Current liabilities	**$ 767.2**	$ 495.1
Long-term debt	**1,790.6**	1,865.3
Other noncurrent liabilities	**240.3**	271.5
Shareholders' equity	**1,888.5**	1,756.8
Total liabilities and shareholders' equity	**$ 4,686.6**	$ 4,388.7

NOTE 19—SEGMENT INFORMATION

At December 31, 2017, we reported six segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility operations of WE, WG, WPS, and UMERC.
- The Illinois segment includes the natural gas utility and non-utility operations of PGL and NSG.
- The other states segment includes the natural gas utility and non-utility operations of MERC and MGU.
- The electric transmission segment includes our approximate 60% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions.
- Following the acquisition of Bluewater, our We Power segment was renamed the non-utility energy infrastructure segment. This segment includes We Power, which owns and leases generating facilities to WE, and Bluewater, which owns underground natural gas storage facilities in Michigan. See Note 2, Acquisitions, for more information on the Bluewater transaction.
- The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Bostco, Wisvest, WECC, WBS, PDL, and ITF. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco and in the second quarter of 2016, we sold certain assets of Wisvest. The sale of ITF was completed in the first quarter of 2016. See Note 3, Dispositions, for more information on these sales.

All of our operations and assets are located within the United States. The following tables show summarized financial information related to our reportable segments for the years ended December 31, 2017, 2016, and 2015.

2017 *(in millions)*	**Utility Operations** Wisconsin	Illinois	Other States	Total Utility Operations	**Electric Transmission**	**Non-Utility Energy Infrastructure**	**Corporate and Other**	**Reconciling Eliminations**	**WEC Energy Group Consolidated**
External revenues	**$ 5,829.2**	**$1,355.5**	**$ 411.2**	**$ 7,595.9**	**$ —**	**$ 38.9**	**$ 13.7**	**$ —**	**$ 7,648.5**
Intersegment revenues	**—**	**—**	**—**	**—**	**—**	**446.3**	**—**	**(446.3)**	**—**
Other operation and maintenance	**1,912.5**	**471.1**	**101.3**	**2,484.9**	**—**	**7.3**	**(4.1)**	**(441.1)**	**2,047.0**
Depreciation and amortization	**523.9**	**152.6**	**24.8**	**701.3**	**—**	**71.4**	**25.9**	**—**	**798.6**
Operating income (loss)	**1,065.9**	**273.0**	**54.2**	**1,393.1**	**—**	**400.5**	**(8.4)**	**—**	**1,785.2**
Equity in earnings of transmission affiliates	**—**	**—**	**—**	**—**	**154.3**	**—**	**—**	**—**	**154.3**
Interest expense	**193.7**	**45.0**	**8.7**	**247.4**	**—**	**62.8**	**107.3**	**(1.8)**	**415.7**
Capital expenditures	**1,152.3**	**545.2**	**74.5**	**1,772.0**	**—**	**35.4**	**152.1**	**—**	**1,959.5**
Total assets *	**22,237.1**	**6,144.7**	**1,067.8**	**29,449.6**	**1,593.4**	**2,992.8**	**953.6**	**(3,398.9)**	**31,590.5**

* Total assets at December 31, 2017 reflect an elimination of $2,038.1 million for all lease activity between We Power and WE.

2016 *(in millions)*	**Utility Operations** Wisconsin	Illinois	Other States	Total Utility Operations	**Electric Transmission**	**Non-Utility Energy Infrastructure**	**Corporate and Other**	**Reconciling Eliminations**	**WEC Energy Group Consolidated**
External revenues	$ 5,805.4	$1,242.2	$ 376.5	$ 7,424.1	$ —	$ 24.9	$ 23.3	$ —	$ 7,472.3
Intersegment revenues	0.3	—	—	0.3	—	423.3	—	(423.6)	—
Other operation and maintenance	2,025.4	485.1	110.1	2,620.6	—	4.3	(15.8)	(423.6)	2,185.5
Depreciation and amortization	496.6	134.0	21.1	651.7	—	68.3	42.6	—	762.6
Operating income (loss)	1,027.0	239.6	49.9	1,316.5	—	375.6	(10.0)	—	1,682.1
Equity in earnings of transmission affiliates	—	—	—	—	146.5	—	—	—	146.5
Interest expense	180.9	38.9	8.5	228.3	—	62.1	120.9	(8.6)	402.7
Capital expenditures	910.9	293.2	59.5	1,263.6	—	62.3	97.8	—	1,423.7
Total assets *	21,730.7	5,714.6	995.1	28,440.4	1,476.9	2,777.1	778.0	(3,349.2)	30,123.2

* Total assets at December 31, 2016 reflect an elimination of $2,029.5 million for all lease activity between We Power and WE.

2015 (in millions)	Utility Operations Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
External revenues	$ 5,186.1	$ 503.4	$ 149.3	$ 5,838.8	$ —	$ 40.0	$ 47.3	$ —	$ 5,926.1
Intersegment revenues	5.0	—	—	5.0	—	405.2	—	(410.2)	—
Other operation and maintenance	1,741.0	219.6	50.0	2,010.6	—	4.3	103.7	(409.3)	1,709.3
Depreciation and amortization	408.6	63.3	10.0	481.9	—	67.5	12.4	—	561.8
Operating income (loss)	884.2	78.1	6.0	968.3	—	373.4	(91.2)	—	1,250.5
Equity in earnings of transmission affiliates	—	—	—	—	96.1	—	—	—	96.1
Interest expense	157.1	19.9	5.1	182.1	—	63.4	91.0	(5.1)	331.4
Capital expenditures	950.3	194.4	34.7	1,179.4	—	53.4	33.4	—	1,266.2
Total assets *	21,113.5	5,462.9	918.0	27,494.4	1,381.0	2,779.0	1,132.5	(3,431.7)	29,355.2

* Total assets at December 31, 2015 reflect an elimination of $2,105.3 million for all lease activity between We Power and WE.

NOTE 20—VARIABLE INTEREST ENTITIES

The primary beneficiary of a variable interest entity must consolidate the entity's assets and liabilities. In addition, certain disclosures are required for significant interest holders in variable interest entities.

We assess our relationships with potential variable interest entities, such as our coal suppliers, natural gas suppliers, coal transporters, natural gas transporters, and other counterparties related to power purchase agreements, investments, and joint ventures. In making this assessment, we consider, along with other factors, the potential that our contracts or other arrangements provide subordinated financial support, the obligation to absorb the entity's losses, the right to receive residual returns of the entity, and the power to direct the activities that most significantly impact the entity's economic performance.

Investment in Transmission Affiliates

We own approximately 60% of ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. We have determined that ATC is a variable interest entity but that consolidation is not required since we are not ATC's primary beneficiary. As a result of our limited voting rights, we do not have the power to direct the activities that most significantly impact ATC's economic performance. We account for ATC as an equity method investment. The significant assets and liabilities related to ATC recorded on our balance sheets were our equity investment, distributions receivable, and accounts payable. At December 31, 2017 and 2016, our equity investment was $1,515.8 million and $1,443.9 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC. In addition, we had receivables of $39.9 million and $35.2 million recorded at December 31, 2017 and 2016, respectively, for distributions from ATC. We also had $31.2 million and $28.7 million of accounts payable due to ATC at December 31, 2017 and 2016, respectively, for network transmission services.

We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. We have determined that ATC Holdco is a variable interest entity but that consolidation is not required since we are not ATC Holdco's primary beneficiary. As a result of our limited voting rights, we do not have the power to direct the activities that most significantly impact ATC Holdco's economic performance. We account for ATC Holdco as an equity method investment. The only significant asset or liability related to ATC Holdco recorded on our balance sheets was our equity investment of $37.6 million at December 31, 2017. This amount approximates our maximum exposure to loss as a result of our involvement with ATC Holdco.

See Note 18, Investment in Transmission Affiliates, for more information.

Purchased Power Agreement

We have a purchased power agreement that represents a variable interest. This agreement is for 236 MW of firm capacity from a natural gas-fired cogeneration facility, and we account for it as a capital lease. The agreement includes no minimum energy requirements over the remaining term of approximately four years. We have examined the risks of the entity, including operations, maintenance, dispatch, financing, fuel costs, and other factors, and have determined that we are not the primary beneficiary of the entity. We do not hold an equity or debt interest in the entity, and there is no residual guarantee associated with the purchased power agreement.

We have approximately $71.4 million of required payments over the remaining term of this agreement. We believe that the required lease payments under this contract will continue to be recoverable in rates. Total capacity and lease payments under this contract for the years ended December 31, 2017, 2016, and 2015, were $18.0 million, $54.2 million, and $53.6 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contract.

NOTE 21—COMMITMENTS AND CONTINGENCIES

We and our subsidiaries have significant commitments and contingencies arising from our operations, including those related to unconditional purchase obligations, operating leases, environmental matters, and enforcement and litigation matters.

Unconditional Purchase Obligations

Our electric utilities have obligations to distribute and sell electricity to their customers, and our natural gas utilities have obligations to distribute and sell natural gas to their customers. The utilities expect to recover costs related to these obligations in future customer rates. In order to meet these obligations, we routinely enter into long-term purchase and sale commitments for various quantities and lengths of time.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2017, including those of our subsidiaries.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2018	2019	2020	2021	2022	Later Years
Electric utility:								
Nuclear	2033	$ 9,184.5	$ 420.1	$ 445.4	$ 475.1	$ 501.1	$ 531.2	$ 6,811.6
Purchased power	2027	645.3	109.3	73.5	72.8	68.9	62.1	258.7
Coal supply and transportation	2024	341.2	223.3	72.0	38.8	2.1	2.1	2.9
Natural gas utility supply and transportation	2043	1,469.9	331.5	294.6	219.2	123.3	78.9	422.4
Total		$ 11,640.9	$ 1,084.2	$ 885.5	$ 805.9	$ 695.4	$ 674.3	$ 7,495.6

Operating Leases

We lease property, plant, and equipment under various terms. The operating leases generally require us to pay property taxes, insurance premiums, and maintenance costs associated with the leased property. Many of our leases contain one of the following options upon the end of the lease term: (a) purchase the property at the current fair market value, or (b) exercise a renewal option, as set forth in the lease agreement.

Rental expense attributable to operating leases was $13.2 million, $15.1 million, and $12.7 million in 2017, 2016, and 2015, respectively.

Future minimum payments under noncancelable operating leases are payable as follows:

Year Ending December 31	Payments *(in millions)*
2018	$ 9.5
2019	9.2
2020	7.6
2021	7.2
2022	7.5
Later years	74.1
Total	$ 115.1

Environmental Matters

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting us include, but are not limited to, current and future regulation of air emissions such as SO_2, NOx, fine particulates, mercury, and GHGs; water intake and discharges; disposal of coal combustion products such as fly ash; and remediation of impacted properties, including former manufactured gas plant sites.

We have continued to pursue a proactive strategy to manage our environmental compliance obligations, including:

- the development of additional sources of renewable electric energy supply;
- the addition of improvements for water quality matters such as treatment technologies to meet regulatory discharge limits and improvements to our cooling water intake systems;
- the addition of emission control equipment to existing facilities to comply with ambient air quality standards and federal clean air rules;
- the protection of wetlands and waterways, threatened and endangered species, and cultural resources associated with utility construction projects;
- the retirement of old coal-fired power plants and conversion to modern, efficient, natural gas generation, super-critical pulverized coal generation, and/or replacement with renewable generation;
- the beneficial use of ash and other products from coal-fired and biomass generating units; and
- the remediation of former manufactured gas plant sites.

Air Quality

Sulfur Dioxide National Ambient Air Quality Standards – The EPA issued a revised 1-Hour SO_2 NAAQS that became effective in August 2010. The EPA issued a final rule in August 2015 describing the implementation requirements and established a compliance timeline for the revised standard. The final rule affords state agencies some latitude in rule implementation. A nonattainment designation could have negative impacts for a localized geographic area, including additional permitting requirements for new or existing sources in the area. In June 2016, we provided modeling to the WDNR that shows the area around the Weston power plant, located in Marathon County, Wisconsin, to be in compliance. In December 2017, the EPA finalized the designation, and Marathon County has been designated attainment. The EPA designated Marquette County, Michigan, where PIPP is located, as unclassified/attainment, effective September 1, 2016. We continue to believe that our fleet overall is well positioned to meet the regulation and do not expect to incur significant costs to comply with this regulation.

8-Hour Ozone National Ambient Air Quality Standards – After completing its review of the 2008 ozone standard, the EPA released a final rule in October 2015, which lowered the limit for ground-level ozone, creating a more stringent standard than the 2008 NAAQS. In December 2017, the EPA designated all the counties along Wisconsin's Lake Michigan shoreline, except Brown, Kewaunee, Marinette, and Oconto Counties, as either partial or full nonattainment. Waukesha and Washington counties were also included due to the counties being in the Milwaukee combined statistical area. For nonattainment areas, the state of Wisconsin will have to develop a state implementation plan to bring the areas back into attainment. We will be required to comply with this state implementation plan no earlier than 2020. Although we will not know the potential impacts for complying with the 2015 ozone NAAQS until the designations are final, which is expected from the EPA in April 2018, and until the state prepares a draft attainment plan, we believe we are well positioned to meet the requirements associated with the ozone standard and do not expect to incur significant costs to comply.

Climate Change – In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the Clean Power Plan, a proposed federal plan and model trading rules as alternatives or guides to state compliance plans, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. In October 2015, following publication of the CPP, numerous states (including Wisconsin and Michigan) and other parties, filed lawsuits challenging the final rule, including a request to stay the implementation of the final rule pending the outcome of these legal challenges. The D.C. Circuit Court of Appeals denied the stay request, but in February 2016, the Supreme Court stayed the effectiveness of the CPP until disposition of the litigation in the D.C. Circuit Court of Appeals and to the extent that further appellate review is sought, at the Supreme Court. The D.C. Circuit Court of Appeals heard one case in September 2016, and the other case is still pending. In April 2017, pursuant to motions made by the EPA, the D.C. Circuit Court of Appeals ordered the cases to be held in abeyance. Supplemental briefs were provided addressing whether the cases should be remanded to the EPA rather than held in abeyance. The EPA argued that the cases should continue to be held in abeyance pending the conclusion of the EPA's review of the CPP and any resulting rulemaking.

The CPP seeks to achieve state-specific GHG emission reduction goals by 2030, and would have required states to submit plans by September 2016. The goal of the final rule is to reduce nationwide GHG emissions by 32% from 2005 levels. The rule is seeking GHG emission reductions in Wisconsin and Michigan of 41% and 39%, respectively, below 2012 levels by 2030. Interim goals starting in 2022 would require states to achieve about two-thirds of the 2030 required reduction.

In March 2017, President Trump issued an executive order that, among other things, specifically directs the EPA to review, and if appropriate, initiate proceedings to suspend, revise, or rescind the CPP and related GHG regulations for new, reconstructed, or modified fossil-fueled power plants. As a result of this order and related EPA review, as well as the ongoing legal proceedings, the timelines for the GHG emission reduction goals and all other aspects of the CPP are uncertain. In April 2017, the EPA withdrew the proposed rule for a federal plan and model trading rules that were published in October 2015 for use in developing state plans to implement the CPP or for use in states where a plan is not submitted or approved. In October 2017, the EPA issued a proposed rulemaking to repeal the CPP. In December 2017, the EPA issued an advanced notice of proposed rulemaking to solicit input on whether it is appropriate to replace the CPP. In addition, the Governor of Wisconsin issued an executive order in February 2016, which prohibits state agencies, departments, boards, commissions, or other state entities from developing or promoting the development of a state plan to implement the CPP.

Notwithstanding the uncertain future of the CPP, and given current fuel and technology markets, we continue to evaluate opportunities and actions that preserve fuel diversity, lower costs for our customers, and contribute towards long-term GHG reductions. Our plan is to work with our industry partners, environmental groups, and the State of Wisconsin, with a goal of reducing CO_2 emissions by approximately 40% below 2005 levels by 2030. We have implemented and continue to evaluate numerous options in order to meet our CO_2 reduction goal, such as increased use of existing natural gas combined cycle units, co-firing or switching to natural gas in existing coal-fired units, reduced operation or retirement of existing coal-fired units, addition of new renewable energy resources (wind, solar), and consideration of supply and demand-side energy efficiency and distributed generation. As a result of our generation reshaping plan, we expect to retire approximately 1,800 MW of coal generation by 2020, including Pleasant Prairie power plant, PIPP, Pulliam power plant, and the jointly-owned Edgewater Unit 4 generation units. See Note 5, Property, Plant, and Equipment, for more information. In addition, we are evaluating our goal, and possible subsequent actions, with respect to national and international efforts to reduce future GHG emissions in order to limit future global temperature increases to less than two degrees Celsius.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2016, we reported aggregated CO_2 equivalent emissions of approximately 29.1 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 29.2 million metric tonnes to the EPA for 2017. The level of CO_2 and other GHG emissions varies from year to year and is dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed, and how our units are dispatched by MISO.

We are also required to report CO_2 equivalent amounts related to the natural gas that our natural gas utilities distribute and sell. For 2016, we reported aggregated CO_2 equivalent emissions of approximately 26.8 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 26.4 million metric tonnes to the EPA for 2017.

Water Quality

Clean Water Act Cooling Water Intake Structure Rule – In August 2014, the EPA issued a final regulation under Section 316(b) of the Clean Water Act, which requires that the location, design, construction, and capacity of cooling water intake structures at existing power plants reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts from both impingement (entrapping organisms on water intake screens) and entrainment (drawing organisms into water intake). The rule became effective in October 2014, and applies to all of our existing generating facilities with cooling water intake structures, except for the ERGS units, which were permitted under the rules governing new facilities.

Facility owners must select from seven compliance options available to meet the impingement mortality (IM) reduction standard. The rule requires state permitting agencies to make BTA determinations, subject to EPA oversight, for IM reduction over the next several years as facility permits are reissued. Based on our assessment, we believe that existing technologies at our generating facilities, except for Pulliam Units 7 and 8 and Weston Unit 2, satisfy the IM BTA requirements. We plan to retire Pulliam Units 7 and 8 as early as late 2018. Therefore, we are not planning to make alterations to the existing water intake at Pulliam Units 7 and 8. We do expect that limited studies will be required to support the future WDNR IM BTA determinations for Weston Unit 2. Based on preliminary discussions with the WDNR, we anticipate that the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the IM BTA requirements based on low capacity use of the unit.

BTA determinations must also be made by the WDNR and MDEQ to address entrainment mortality (EM) reduction on a site-specific basis taking into consideration several factors. We have received an EM BTA determination by the WDNR, with EPA concurrence, for our intake modification at VAPP. Due to our plans to retire Pulliam Units 7 and 8, PIPP, and Pleasant Prairie power plant, we do not believe that BTA determinations for EM will be necessary for these facilities. Although we currently believe that, other than Weston Unit 2, existing technologies at Weston Units 3 and 4, PWGS, and OC 5 through OC 8 satisfy the EM BTA requirements, BTA determinations to address EM reduction requirements will not be made until discharge permits are renewed for these facilities. Until that time, with the exception of Weston Units 3 and 4, which have existing cooling towers that meet EM BTA requirements, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new EM BTA requirements at the other facilities. We also expect that limited studies to support WDNR EM

BTA determinations will be conducted at the Weston facility. During 2018, we will continue to evaluate options to address the EM BTA requirements at these plants.

We have also provided information to the WDNR and the MDEQ about planned unit retirements. Based on discussions with the MDEQ, if we submit a signed certification stating that PIPP will be retired no later than the end of the next permit cycle (assumed to be October 1, 2023), the EM BTA requirements will be waived. We expect to submit the letter identifying the last operating date for PIPP to the MDEQ during 2018, ahead of when the agency begins processing our pending application for the National Pollutant Discharge Elimination System permit reissuance. For Pulliam Units 7 and 8, we submitted our 2016 and 2017 entrainment studies to the WDNR in December 2017, with the application to renew our existing discharge permit.

We believe our fleet overall is well positioned to meet the new regulation and do not expect to incur significant costs to comply with this regulation.

Steam Electric Effluent Limitation Guidelines – The EPA's final steam electric effluent limitation guidelines (ELG) rule took effect in January 2016. Various petitions challenging the rule were consolidated and are pending in the United States Fifth Circuit Court of Appeals. In April 2017, the EPA issued an administrative stay of certain compliance deadlines while further reviewing the rule. In September 2017, the EPA issued a final rule to postpone the earliest compliance dates for the bottom ash transport water and wet flue gas desulfurization wastewater requirements. This rule applies to wastewater discharges from our power plant processes in Wisconsin and Michigan. While the ELG compliance deadlines are postponed, the WDNR and the MDEQ have indicated that they will refrain from incorporating certain new requirements into any reissued discharge permits between 2018 and 2023.

After a final rule is back in effect, the WDNR and MDEQ have indicated that they will modify the state rules as necessary and incorporate the new requirements into our facility permits, which are renewed every five years. Our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. However, as currently constructed, the ELG rule will require additional wastewater treatment retrofits as well as installation of other equipment to minimize process water use.

The final rule would phase in new or more stringent requirements related to limits of arsenic, mercury, selenium, and nitrogen in wastewater discharged from wet scrubber systems. New requirements for wet scrubber wastewater treatment would require additional zero liquid discharge or other advanced treatment capital improvements for the OCPP and ERGS. The rule also would require dry fly ash handling, which is already in place at all of our power plants. Dry bottom ash transport systems are required by the new rule, and modifications would be required at OC 7, OC 8, and Weston Unit 3. We are beginning preliminary engineering for compliance with the rule and estimate approximately $70 million will be required to design and install these advanced treatment and bottom ash transport systems. This estimate reflects the planned retirements of certain of our generation plants as a result of our generation reshaping plan discussed in Climate Change above.

Land Quality

Manufactured Gas Plant Remediation – We have identified sites at which our utilities or a predecessor company owned or operated a manufactured gas plant or stored manufactured gas. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Our natural gas utilities are responsible for the environmental remediation of these sites, some of which are in the EPA Superfund Alternative Approach Program. We are also working with various state jurisdictions in our investigation and remediation planning. These sites are at various stages of investigation, monitoring, remediation, and closure.

In addition, we are coordinating the investigation and cleanup of some of these sites subject to the jurisdiction of the EPA under what is called a "multisite" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

The future costs for detailed site investigation, future remediation, and monitoring are dependent upon several variables including, among other things, the extent of remediation, changes in technology, and changes in regulation. Historically, our regulators have allowed us to recover incurred costs, net of insurance recoveries and recoveries from potentially responsible parties, associated with the remediation of manufactured gas plant sites. Accordingly, we have established regulatory assets for costs associated with these sites.

We have established the following regulatory assets and reserves related to manufactured gas plant sites as of December 31:

(in millions)	**2017**	**2016**
Regulatory assets	**$ 676.6**	$ 702.7
Reserves for future remediation	**617.2**	633.4

Renewables, Efficiency, and Conservation

Wisconsin Legislation – In 2005, Wisconsin enacted Act 141, which established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. WE and WPS have achieved renewable energy percentages of 8.27% and 9.74%, respectively, and met their compliance requirements by constructing various wind parks, a biomass facility, and by also relying on renewable energy purchases. WE and WPS continue to review their renewable energy portfolios and acquire cost-effective renewables as needed to meet their requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and each utility funds the program based on 1.2% of its annual operating revenues.

Michigan Legislation – In 2008, Michigan enacted Act 295, which required 10% of the state's electric energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. In December 2016, Michigan revised this legislation with Act 342, which requires additional renewable energy requirements beyond 2015. The new legislation retains the 10% renewable energy portfolio requirement for years 2017 through 2018, increases the requirement to 12.5% for years 2019 through 2020, and increases the requirement to 15.0% for 2021. WE and UMERC were in compliance with these requirements as of December 31, 2017. The revised legislation continues to allow recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective.

Enforcement and Litigation Matters

We and our subsidiaries are involved in legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business. Although we are unable to predict the outcome of these matters, management believes that appropriate reserves have been established and that final settlement of these actions will not have a material effect on our financial condition or results of operations.

Consent Decrees

Wisconsin Public Service Corporation Consent Decree – Weston and Pulliam Power Plants – In November 2009, the EPA issued a NOV to WPS, which alleged violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam power plants from 1994 to 2009. WPS entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Eastern District of Wisconsin in March 2013.

The final Consent Decree includes:

- the installation of emission control technology, including ReACT™ on Weston 3,
- changed operating conditions,
- limitations on plant emissions,
- beneficial environmental projects totaling $6.0 million, and
- a civil penalty of $1.2 million.

The Consent Decree also contains requirements to refuel, repower, and/or retire certain Weston and Pulliam units. Effective June 1, 2015, WPS retired Weston Unit 1 and Pulliam Units 5 and 6. In May 2016, the EPA approved WPS's proposed revision to update requirements reflecting the conversion of Weston Unit 2 from coal to natural gas fuel, and also proposed revisions to the list of beneficial environmental projects required by the Consent Decree. WPS anticipates retirement of the remaining Pulliam units in 2018. See Note 5, Property, Plant, and Equipment, for more information about the retirement.

WPS received approval from the PSCW in its 2015 rate order to defer and amortize the undepreciated book value of the retired plant related to Weston Unit 1 and Pulliam Units 5 and 6 starting June 1, 2015, and concluding by 2023. Therefore, in June 2015, WPS recorded a regulatory asset of $11.5 million for the undepreciated book value. In addition, WPS received approval from the PSCW in its rate orders to recover prudently incurred costs as a result of complying with the terms of the Consent Decree, with the exception of the civil penalty.

Joint Ownership Power Plants Consent Decree – Columbia and Edgewater – In December 2009, the EPA issued a NOV to Wisconsin Power and Light, the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric, WE (former co-owner of an Edgewater unit), and WPS. The NOV alleged violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WPS, along with Wisconsin Power and Light, Madison Gas and Electric, and WE, entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Western District of Wisconsin in June 2013. WE paid an immaterial portion of the assessed penalty but has no further obligations under the Consent Decree.

The final Consent Decree includes:

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions,
- limitations on plant emissions,
- beneficial environmental projects, with WPS's portion totaling $1.3 million, and
- WPS's portion of a civil penalty and legal fees totaling $0.4 million.

The Consent Decree contains a requirement to, among other things, refuel, repower, or retire Edgewater Unit 4, of which WPS is a joint owner, by no later than December 31, 2018. Management of the joint owners has recommended that Edgewater Unit 4 be retired by September 30, 2018. See Note 5, Property, Plant, and Equipment, for more information about the retirement.

NOTE 22—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2017	2016	2015
Cash (paid) for interest, net of amount capitalized	**$ (413.7)**	$ (411.9)	$ (329.6)
Cash received (paid) for income taxes, net	**5.2**	39.7	(9.3)
Significant non-cash transactions:			
Accounts payable related to construction costs	**169.2**	170.1	177.1
Increase (decrease) in restricted cash from the sale (purchase) of investments held in the rabbi trust	**4.6**	(59.2)	(60.2)
Portion of Bostco real estate holdings sale financed with note receivable [(1)]	**7.0**	—	—
Amortization of deferred revenue	**24.9**	24.7	39.9
Note receivable received related to the sale of AMP Trillium LLC [(2)]	**—**	—	12.0
Capital assets received related to the sale of AMP Trillium LLC [(2)]	**—**	—	6.3

(1) See Note 3, Dispositions, for more information on this sale.

(2) ITF owned a 30% interest in AMP Trillium LLC. See Note 3, Dispositions, for more information on the sale of ITF.

At December 31, 2017 and 2016, restricted cash of $19.7 million and $33.6 million, respectively, was recorded within other long-term assets on our balance sheets. The majority of this amount was held in the Integrys rabbi trust and represents a portion of the required funding that was triggered by the announcement of the Integrys acquisition. Withdrawals of restricted cash from the rabbi trust for qualifying payments are shown as an investing activity on the statements of cash flows. Changes in restricted cash due to the sale or purchase of investments held in the rabbi trust are non-cash transactions and are included in the table above.

NOTE 23—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

WEC Energy Group's regulated utilities deferred for return to ratepayers, through future refunds, bill credits, riders, or reductions in other regulatory assets, the estimated tax benefit of $2,450 million related to the Tax Legislation that was signed into law in December 2017. This tax benefit resulted from the revaluation of deferred taxes. See Note 13, Income Taxes, for more information.

Wisconsin Electric Power Company, Wisconsin Gas, and Wisconsin Public Service Corporation

2018 and 2019 Rates

During April 2017, WE, WG, and WPS filed an application with the PSCW for approval of a settlement agreement they made with several of their commercial and industrial customers regarding 2018 and 2019 base rates. In September 2017, the PSCW issued an order that approved the settlement agreement, which freezes base rates through 2019 for electric, gas, and steam customers of WE, WG, and WPS. Based on the PSCW order, the authorized ROE for WE, WG, and WPS remains at 10.2%, 10.3%, and 10.0%, respectively, and the current capital cost structure for all of our Wisconsin utilities will remain unchanged through 2019. Various intervenors had filed requests for rehearing, all of which have been denied.

In addition to freezing base rates, the settlement agreement extends and expands the electric real-time market pricing program options for large commercial and industrial customers and mitigates the continued growth of certain escrowed costs at WE during the base rate freeze period by accelerating the recognition of certain tax benefits. The agreement also allows WPS to extend through 2019, the deferral for the revenue requirement of ReACT™ costs above the authorized $275.0 million level, and other deferrals related to WPS's electric real-time market pricing program and network transmission expenses. The total cost of the ReACT™ project, excluding $51 million of AFUDC, is currently estimated to be $342 million.

Pursuant to the settlement agreement, WPS also agreed to adopt, beginning in 2018, the earnings sharing mechanism that has been in place for WE and WG since 2016, and all three utilities agreed to keep the mechanism in place through 2019. Under this earnings sharing mechanism, if WE, WG, or WPS earns above its authorized ROE, 50% of the first 50 basis points of additional utility earnings must be shared with customers. All utility earnings above the first 50 basis points must also be shared with customers.

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, WPS, along with two other unaffiliated utilities, entered into an agreement to purchase the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MW. The FERC approved the transaction in January 2018. The transaction remains subject to PSCW approval and is expected to close in the spring of 2018. See Note 2, Acquisitions, for more information.

Natural Gas Storage Facilities in Michigan

In January 2017, we signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that would provide approximately one-third of the current storage needs for the natural gas operations of WE, WG, and WPS. As a result of this agreement, WE, WG, and WPS filed a request with the PSCW in February 2017 for a declaratory ruling on various items associated with the storage facilities. In the filing, WE, WG, and WPS requested that the PSCW review and confirm the reasonableness and prudency of their potential long-term storage service agreements and interstate natural gas transportation contracts related to the storage facilities. WE, WG, and WPS also requested approval to amend our Affiliated Interest Agreement to ensure WBS and our other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and we acquired Bluewater on June 30, 2017. In September 2017, WE, WG, and WPS entered into the long-term service agreements for the natural gas storage, which were approved by the PSCW in November 2017. See Note 2, Acquisitions, for more information.

2015 Wisconsin Electric Power Company Rate Order

In May 2014, WE applied to the PSCW for a biennial review of costs and rates. In December 2014, the PSCW approved the following rate adjustments, effective January 1, 2015:

- A net bill increase related to non-fuel costs for WE's retail electric customers of approximately $2.7 million (0.1%) in 2015. This amount reflected WE's receipt of SSR payments from MISO that were higher than WE anticipated when it filed its rate request in May 2014, as well as an offset of $26.6 million related to a refund of prior fuel costs and the remainder of the proceeds from a Treasury Grant that WE received in connection with its biomass facility. The majority of this $26.6 million was returned to customers in the form of bill credits in 2015.
- A rate increase for WE's retail electric customers of $26.6 million (0.9%) in 2016 related to the expiration of the bill credits provided to customers in 2015.
- A rate decrease of $13.9 million (-0.5%) in 2015 related to a forecasted decrease in fuel costs.
- A rate decrease of $10.7 million (-2.4%) for WE's natural gas customers in 2015, with no rate adjustment in 2016.
- A rate increase of approximately $0.5 million (2.0%) for WE's Downtown Milwaukee (Valley) steam utility customers in 2015, with no rate adjustment in 2016.
- A rate increase of approximately $1.2 million (7.3%) for WE's Milwaukee County steam utility customers in 2015, with no rate adjustment in 2016. As a result of the sale of the MCPP, WE no longer has any Milwaukee County steam utility customers. See Note 3, Dispositions, for more information about the sale of the MCPP.

The authorized ROE for WE was set at 10.2%, and its common equity component remained at an average of 51%. The PSCW order reaffirmed the deferral of WE's transmission costs, and it verified that 2015 and 2016 fuel costs should continue to be monitored using a 2% tolerance window. The PSCW order also authorized escrow accounting for SSR revenues because of the uncertainty of the actual revenues WE will receive under the PIPP SSR agreements. Under escrow accounting, WE records SSR revenues of $90.7 million a year. If actual SSR payments from MISO exceed $90.7 million a year, the difference is deferred and returned to customers, with interest, in a future rate case. If actual SSR payments from MISO are less than $90.7 million a year, the difference is deferred and is expected to be recovered from customers with interest, in a future rate case.

Earnings Sharing Agreement

In May 2015, the PSCW approved the acquisition of Integrys subject to the condition of an earnings sharing mechanism for WE. See Note 2, Acquisitions, for more information on this earnings sharing mechanism.

2015 Wisconsin Gas Rate Order

In May 2014, WG applied to the PSCW for a biennial review of costs and rates. In December 2014, the PSCW approved rate increases of $17.1 million (2.6%) in 2015 and $21.4 million (3.2%) in 2016 for WG's natural gas customers. These rate adjustments were effective January 1, 2015. The authorized ROE for WG was set at 10.3%. The PSCW also authorized an increase in WG's common equity component to an average of 49.5%.

Earnings Sharing Agreement

In May 2015, the PSCW approved the acquisition of Integrys subject to the condition of an earnings sharing mechanism for WG. See Note 2, Acquisitions, for more information on this earnings sharing mechanism.

2016 Wisconsin Public Service Corporation Rate Order

In April 2015, WPS initiated a rate proceeding with the PSCW. In December 2015, the PSCW issued a final written order for WPS, effective January 1, 2016. The order, which reflects a 10.0% ROE and a common equity component average of 51.0%, authorized a net retail electric rate decrease of $7.9 million (-0.8%) and a net retail natural gas rate decrease of $6.2 million (-2.1%). The decrease in retail electric rates was due to lower monitored fuel costs in 2016 compared with 2015. Absent the adjustment for electric fuel costs, WPS would have realized an electric rate increase. Based on the order, the PSCW allowed WPS to escrow ATC and MISO network transmission expenses through 2016. In addition, SSR payments are escrowed until a future rate proceeding. The order directed WPS to defer as a regulatory asset or liability the differences between actual transmission expenses and those included in rates. In addition, the PSCW approved a deferral for ReACT™, which required WPS to defer the revenue requirement of ReACT™ costs above the authorized $275.0 million level through 2016. Fuel costs will continue to be monitored using a 2% tolerance window.

In March 2016, WPS requested extensions from the PSCW through 2017 for the deferral of the revenue requirement of ReACT™ costs above the authorized $275.0 million level as well as escrow accounting of ATC and MISO network transmission expenses. In April 2016, WPS also requested to extend through 2017 the previously approved deferral of the revenue requirement difference between the Real Time Market Pricing and the standard tariffed rates for any of WPS's large commercial and industrial customers who entered into a service agreement with WPS under Real Time Market Pricing prior to April 15, 2016. These requests were approved by the PSCW in June 2016.

2015 Wisconsin Public Service Corporation Rate Order

In April 2014, WPS initiated a rate proceeding with the PSCW. In December 2014, the PSCW issued a final written order for WPS, effective January 1, 2015. It authorized a net retail electric rate increase of $24.6 million and a net retail natural gas rate decrease of $15.4 million, reflecting a 10.2% ROE. The order authorized a common equity component average of 50.28%. The PSCW approved a change in rate design for WPS, which included higher fixed charges to better match the related fixed costs of providing service. In addition, the order continued to exclude a decoupling mechanism that was terminated beginning January 1, 2014.

The primary driver of the increase in retail electric rates was higher costs of fuel for electric generation of approximately $42.0 million. In addition, 2015 rates included approximately $9.0 million of lower refunds to customers related to decoupling over-collections. In addition, WPS received approval from the PSCW to defer and amortize the undepreciated book value associated with Pulliam Units 5 and 6 and Weston Unit 1 starting with the actual retirement date, June 1, 2015, and concluding by 2023. See Note 21, Commitments and Contingencies, for more information. The PSCW allowed WPS to escrow ATC and MISO network transmission expenses for 2015 and 2016. As a result, WPS deferred as a regulatory asset the difference between actual transmission expenses and those included in rates until a future rate proceeding. Finally, the PSCW ordered that 2015 fuel costs should continue to be monitored using a 2% tolerance window.

The retail natural gas rate decrease was driven by the approximate $16.0 million year-over-year negative impact of decoupling refunds to and collections from customers between 2015 and 2014.

The Peoples Gas Light and Coke Company and North Shore Gas Company

Base Rate Freeze

In June 2015, the ICC approved the acquisition of Integrys subject to the condition that PGL and NSG will not seek increases of their base rates that would become effective earlier than two years after the close of the acquisition. This base rate freeze expired in 2017 and did not impact PGL's or NSG's ability to adjust rates through various riders or GCRMs.

Illinois Proceedings

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate PGL's SMP. This ICC action did not impact PGL's ongoing work to modernize and maintain the safety of its natural gas distribution system, but it instead provided the ICC with an opportunity to analyze long-term elements of the program through the stakeholder workshops. The workshops were completed in March 2016. In July 2016, the ICC initiated a proceeding to review, among other things, the planning, reporting, and monitoring of the program, including the target end date for the program. In March 2017, the ICC issued an order directing that additional hearings be held before the ALJ on certain issues to further develop the evidentiary record in the case. This proceeding resulted in a final order issued by the Commission in January 2018. The order did not have a significant impact on PGL's existing SMP design and execution.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. This law provides PGL with a cost recovery mechanism that allows collection, through a surcharge on customer bills, of prudently incurred costs to upgrade Illinois natural gas infrastructure. In September 2013, PGL filed with the ICC requesting the proposed rider, which was approved in January 2014.

PGL's QIP rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2017, PGL filed its 2016 reconciliation with the ICC, which, along with the 2015 reconciliation, is still pending. In February 2018, PGL agreed to a settlement of the 2014 reconciliation, which includes a rate base reduction of $5.4 million and a $4.7 million refund to ratepayers. As of December 31, 2017, there can be no assurance that all costs incurred under PGL's QIP rider during the open reconciliation years will be deemed recoverable by the ICC.

2015 Illinois Rate Order

In February 2014, PGL and NSG initiated a rate proceeding with the ICC. In January 2015, the ICC issued a final written order for PGL and NSG, effective January 28, 2015. The order authorized a retail natural gas rate increase of $74.8 million for PGL and $3.7 million for NSG. In February 2015, the ICC issued an amendatory order that revised the increases to $71.1 million for PGL and $3.5 million for NSG, effective February 26, 2015, to reflect the extension of bonus depreciation in 2014. The rates for PGL reflected a 9.05% ROE and a common equity component average of 50.33%. The rates for NSG reflected a 9.05% ROE and a common equity component average of 50.48%. The rate order allowed PGL and NSG to continue the use of their decoupling mechanisms and uncollectible expense true-up mechanisms. In addition, as previously discussed, PGL recovers a return on certain investments and depreciation expense through the QIP rider, and accordingly, such costs are not subject to PGL's rate order.

Minnesota Energy Resources Corporation

2018 Minnesota Rate Case

In October 2017, MERC initiated a rate proceeding with the MPUC to increase retail natural gas rates $12.6 million (5.05%). MERC's request reflects a 10.3% ROE and a common equity component average of 50.9%. The proposed retail natural gas rate increase is primarily driven by increased capital investments as well as general inflation. MERC is also requesting authority from the MPUC to continue the use of its currently authorized decoupling mechanism.

In November 2017, the MPUC approved an interim rate order, effective January 1, 2018, authorizing a retail natural gas rate increase for MERC of $9.5 million (3.78%). The interim rates reflect a 9.11% ROE and a common equity component average of 50.9%. The interim rate increase is subject to refund pending the final written rate order, which is expected in the first half of 2019.

2016 Minnesota Rate Case

In September 2015, MERC initiated a rate proceeding with the MPUC. In October 2016, the MPUC issued a final written order for MERC, effective March 1, 2017. The order authorized a retail natural gas rate increase of $6.8 million (3.0%). The rates reflected a 9.11% ROE and a common equity component average of 50.32%. The order approved MERC's request to continue the use of its decoupling mechanism for another three years. The final approved rate increase was lower than the interim rates collected from customers during 2016. Therefore, we refunded $4.1 million to MERC's customers in 2017.

2015 Minnesota Rate Case

In September 2013, MERC initiated a rate proceeding with the MPUC. In October 2014, the MPUC issued a final written order for MERC, effective April 1, 2015. The order authorized a retail natural gas rate increase of $7.6 million. The rates reflected a 9.35% ROE and a common equity component average of 50.31%. The order approved a deferral of customer billing system costs, for which recovery was requested in MERC's 2016 rate case. The order also approved MERC's request to continue the use of its decoupling mechanism with a 10% cap for residential and small commercial and industrial customers. The final approved rate increase was lower than the interim rates collected from customers during 2014. Therefore, MERC refunded $4.7 million to customers in 2015.

Michigan Gas Utilities Corporation

2016 Michigan Rate Order

In June 2015, MGU initiated a rate proceeding with the MPSC. In December 2015, the MPSC issued a final written order approving a settlement agreement for MGU. The order, which reflects a 9.9% ROE and a common equity component average of 52.0%, authorized a retail natural gas rate increase of $3.4 million (2.4%), effective January 1, 2016. Based on the settlement agreement, MGU discontinued the use of its decoupling mechanism after December 31, 2015. In addition, since bonus depreciation was in effect in 2016, MGU established a regulatory liability for the resulting cost savings and must refund the liability in its next general rate case.

Upper Michigan Energy Resources Corporation

Formation of Upper Michigan Energy Resources Corporation

In December 2016, both the MPSC and the PSCW approved the operation of UMERC as a stand-alone utility in the Upper Peninsula of Michigan, and UMERC became operational effective January 1, 2017. This utility holds the electric and natural gas distribution assets, previously held by WE and WPS, located in the Upper Peninsula of Michigan.

In August 2016, we entered into an agreement with Tilden under which it will purchase electric power from UMERC for its iron ore mine for 20 years, contingent upon UMERC's construction of approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan.

In October 2017, the MPSC approved both the agreement with Tilden and UMERC's application for a certificate of necessity to begin construction of the proposed generation. The estimated cost of this project is $266 million ($277 million with AFUDC), 50% of which is expected to be recovered from Tilden, with the remaining 50% expected to be recovered from UMERC's other utility customers. The new units are expected to begin commercial operation in 2019 and should allow for the retirement of PIPP no later than 2020. Tilden will remain a customer of WE until this new generation begins commercial operation.

2015 Rate Order

In October 2014, WPS initiated a rate proceeding with the MPSC. In April 2015, the MPSC issued a final written order for WPS, effective April 24, 2015, approving a settlement agreement. The order authorized a retail electric rate increase of $4.0 million to be implemented over three years to recover costs for the 2013 acquisition of the Fox Energy Center as well as other capital investments associated with the Crane Creek wind farm and environmental upgrades at generation plants. The rates reflected a 10.2% ROE and a common equity component average of 50.48%. The increase reflected the continued deferral of costs associated with the Fox Energy Center until the second anniversary of the order. The increase also reflected the deferral of Weston Unit 3 ReACT™ environmental project costs. On the second anniversary of the order, WPS discontinued the deferral of the Fox Energy Center costs and began amortizing this deferral along with the deferral associated with the termination of a tolling agreement related to the Fox Energy Center. WPS also received approval from the MPSC to defer and amortize the undepreciated book value of the retired plant associated with Pulliam Units 5 and 6 and Weston Unit 1 starting with the actual retirement date, June 1, 2015, and concluding by 2023. As a result of the formation of UMERC, WPS transferred the deferrals mentioned above, as well as its customers and property, plant, and equipment located in the Upper Peninsula of Michigan to the new utility, effective January 1, 2017. Therefore, the terms and conditions of this rate order were applicable to UMERC starting January 1, 2017.

NOTE 24—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

(in millions)	2017	2016	2015
AFUDC – Equity	**$ 11.4**	$ 25.1	$ 20.1
Gain on repurchase of notes	**—**	23.6	—
Gain on asset sales	**1.9**	19.6	22.9
Other, net	**51.3**	12.5	15.9
Other income, net	**$ 64.6**	$ 80.8	$ 58.9

NOTE 25—QUARTERLY FINANCIAL INFORMATION (Unaudited)

(in millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	$ **2,304.5**	$ **1,631.5**	$ **1,657.5**	$ **2,055.0**	$ **7,648.5**
Operating income	**617.3**	**362.2**	**393.6**	**412.1**	**1,785.2**
Net income attributed to common shareholders	**356.6**	**199.1**	**215.4**	**432.6**	**1,203.7**
Earnings per share *					
Basic	$ **1.13**	$ **0.63**	$ **0.68**	$ **1.37**	$ **3.81**
Diluted	**1.12**	**0.63**	**0.68**	**1.36**	**3.79**
2016					
Operating revenues	$ 2,194.8	$ 1,602.0	$ 1,712.5	$ 1,963.0	$ 7,472.3
Operating income	589.3	332.1	399.0	361.7	1,682.1
Net income attributed to common shareholders	346.2	181.4	217.0	194.4	939.0
Earnings per share *					
Basic	$ 1.10	$ 0.57	$ 0.69	$ 0.62	$ 2.98
Diluted	1.09	0.57	0.68	0.61	2.96

* Earnings per share for the individual quarters may not total the year ended earnings per share amount because of changes to the average number of shares outstanding and changes in incremental issuable shares throughout the year.

NOTE 26—NEW ACCOUNTING PRONOUNCEMENTS

Revenue Recognition

In May 2014, the FASB and the International Accounting Standards Board issued their joint revenue recognition standard, ASU 2014-09, Revenue from Contracts with Customers. Several amendments were issued subsequent to the standard to clarify the guidance. The core principle of the guidance is to recognize revenue in an amount that an entity is entitled to receive in exchange for goods and services. The guidance also requires additional disclosures about the nature, amount, timing, and uncertainty of revenues and the related cash flows arising from contracts with customers.

We have completed the review of our contracts with customers and are finalizing the related financial disclosures to evaluate the impact of the amended guidance on our existing revenue recognition policies and procedures. We have evaluated the nature of our operating revenues and do not expect that there will be a significant shift in the timing or pattern of revenue recognition. Most of our revenues are from tariff sales at our regulated utilities, which are in the scope of the new standard, excluding the revenue component related to alternative revenue programs. The revenues from these contracts are recorded at the amount of the electricity or natural gas delivered to the customer during the period.

We adopted this standard for interim and annual periods beginning January 1, 2018, as required, and used the modified retrospective method of adoption. The most significant impact to the financial statements is expected to be in the form of additional disclosures. However, we do not expect to have a cumulative-effect adjustment to record on the balance sheet as of the beginning of 2018; and therefore, do not expect to include a reconciliation of results under the new revenue recognition guidance compared with what would have been reported in 2018 under the old revenue recognition guidance. We will include disaggregated revenue disclosures by segment, major products (electric and natural gas), and customer class in the combined notes to the financial statements, starting in the first quarter of 2018.

Recognition and Measurement of Financial Instruments

In January 2016, the FASB issued ASU 2016-01, Recognition and Measurement of Financial Assets and Liabilities. This guidance requires equity investments, including other ownership interests such as partnerships, unincorporated joint ventures, and limited liability companies, to be measured at fair value with changes in fair value recognized in net income. It also simplifies the impairment assessment of equity investments without readily determinable fair values and amends certain disclosure requirements associated with the fair value of financial instruments. This ASU does not apply to investments accounted for under the equity method of accounting. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

Leases

In February 2016, the FASB issued ASU 2016-02, Leases. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, and will be applied using a modified retrospective approach. The main provision of this ASU is that lessees will be required to recognize lease assets and lease liabilities for most leases, including those classified as operating leases under GAAP. We are currently assessing the effects this guidance may have on our financial statements.

Financial Instruments Credit Losses

In June 2016, the FASB issued ASU 2016-13, Measurement of Credit Losses on Financial Instruments. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. This ASU introduces a new impairment model known as the current expected credit loss model. The ASU requires a financial asset measured at amortized cost to be presented at the net amount expected to be collected. Previously, recognition of the full amount of credit losses was generally delayed until the loss was probable of occurring. We are currently assessing the effects this guidance may have on our financial statements.

Classification of Certain Cash Receipts and Cash Payments

In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments. There are eight main provisions of this ASU for which current GAAP either is unclear or does not include specific guidance. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018 and used a retrospective transition method. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

Restricted Cash

In November 2016, the FASB issued ASU 2016-18, Restricted Cash. Under this ASU, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-the period and end-of-the period total amounts shown on the statements of cash flows. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. Under this ASU, an employer is required to disaggregate the service cost component from the other components of the net benefit cost. The amendments provide explicit guidance on how to present the service cost component and the other components of the net benefit cost in the income statement and allow only the service cost component of the net benefit cost to be eligible for capitalization. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. The amendments will be applied retrospectively for the presentation of the service cost component and the other components of the net benefit cost in the income statement, and prospectively for the capitalization of the service cost component in assets. As a result of the application of accounting principles for rate regulated entities, a similar amount of net benefit cost (including non-service components) will be recognized in our financial statements consistent with the current rate-making treatment. The impacts of adoption will be limited to changes in classification of non-service costs in the income statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of WEC Energy Group, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets and statements of capitalization of WEC Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017 and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2018 expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Deloitte & Touche LLP

Milwaukee, Wisconsin
February 28, 2018

We have served as the Company's auditor since 2002.

Deloitte.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of WEC Energy Group, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of WEC Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2017, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 28, 2018 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte & Touche LLP

February 28, 2018

INTERNAL CONTROL OVER FINANCIAL REPORTING

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our and our subsidiaries' internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that our and our subsidiaries' internal control over financial reporting was effective as of December 31, 2017.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

For Deloitte & Touche LLP's Report of Independent Registered Public Accounting Firm, attesting to the effectiveness of our internal controls over financial reporting, see Page F-90.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in our internal control over financial reporting during the fourth quarter of 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

WEC ENERGY GROUP, INC.
COMPARATIVE SELECTED FINANCIAL DATA AND OTHER STATISTICS

As of or for Year Ended December 31 ***(in millions, except per share information)***	**2017 (1)**	**2016**	**2015 (2)**	**2014**	**2013**
Operating revenues	**$ 7,648.5**	$ 7,472.3	$ 5,926.1	$ 4,997.1	$ 4,519.0
Net income attributed to common shareholders	**1,203.7**	939.0	638.5	588.3	577.4
Total assets	**31,590.5**	30,123.2	29,355.2	14,905.0	14,443.2
Preferred stock of subsidiary	**30.4**	30.4	30.4	30.4	30.4
Long-term debt (excluding current portion)	**8,746.6**	9,158.2	9,124.1	4,170.7	4,347.0
Weighted average common shares outstanding					
Basic	**315.6**	315.6	271.1	225.6	227.6
Diluted	**317.2**	316.9	272.7	227.5	229.7
Earnings per share					
Basic	**$ 3.81**	$ 2.98	$ 2.36	$ 2.61	$ 2.54
Diluted	**$ 3.79**	$ 2.96	$ 2.34	$ 2.59	$ 2.51
Dividends per share of common stock	**$ 2.08**	$ 1.98	$ 1.74	$ 1.56	$ 1.45

(1) Includes the impact of the enactment of the Tax Legislation. See Note 13, Income Taxes, for more information.

(2) Includes the impact of the Integrys acquisition for the last two quarters of 2015. See Note 2, Acquisitions, for more information.

PERFORMANCE GRAPH

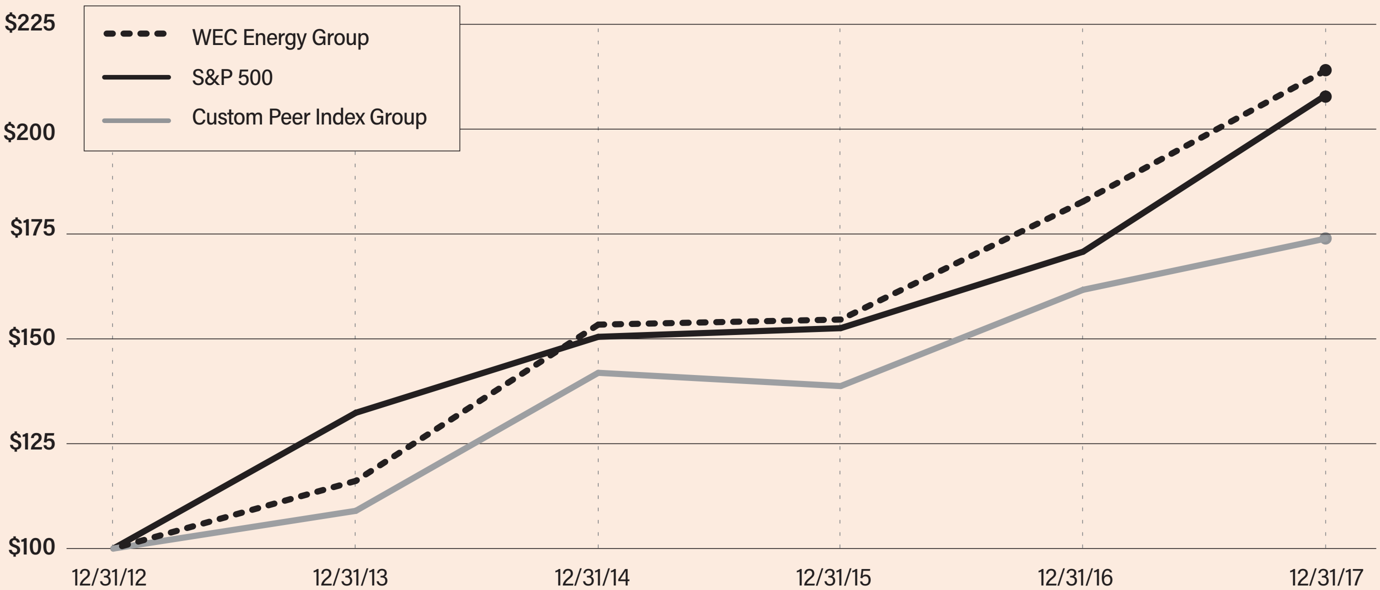
The performance graph below shows a comparison of the cumulative total return, assuming reinvestment of dividends, over the last five years had $100 been invested at the close of business on December 31, 2012, in each of:

- WEC Energy Group common stock;
- a Custom Peer Group Index; and
- the Standard & Poor's 500 Index ("S&P 500").

Custom Peer Group Index. We have used the Custom Peer Group Index for peer comparison purposes because we believe the Index provides an accurate representation of our peers. The Custom Peer Group Index is a market capitalization-weighted index of companies, including WEC Energy Group, that are similar to us in terms of size and business model.

In addition to WEC Energy Group, the companies in the Custom Peer Group Index are: Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; CMS Energy Corporation, Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; Edison International; Eversource Energy; FirstEnergy Corp.; Great Plains Energy, Inc.; NiSource Inc.; OGE Energy Corp.; PG&E Corporation; Pinnacle West Capital Corporation; SCANA Corporation; The Southern Company; and Xcel Energy Inc.

Five-Year Cumulative Return



Value of Investment at Year-End

	12/31/12	12/31/13	12/31/14	12/31/15	12/31/16	12/31/17
WEC Energy Group, Inc.	$100	$116.13	$153.39	$154.60	$182.76	$213.98
Custom Peer Group Index	$100	$108.99	$141.90	$138.74	$161.70	$173.89
S&P 500	$100	$132.37	$150.48	$152.55	$170.78	$208.05

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

NUMBER OF COMMON STOCKHOLDERS

As of January 31, 2018, based upon the number of WEC Energy Group shareholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 50,000 registered shareholders.

COMMON STOCK LISTING AND TRADING

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WEC."

DIVIDENDS AND COMMON STOCK PRICES

Common Stock Dividends of WEC Energy Group

Cash dividends on our common stock, as declared by our Board of Directors, are normally paid on or about the first day of March, June, September, and December of each year. We review our dividend policy on a regular basis. Subject to any regulatory restrictions or other limitations on the payment of dividends, future dividends will be at the discretion of the Board of Directors and will depend upon, among other factors, earnings, financial condition, and other requirements. For information regarding restrictions on the ability of our subsidiaries to pay us dividends, see Note 9, Common Equity.

On January 18, 2018, the Board of Directors increased the quarterly dividend to $0.5525 per share effective with the first quarter of 2018 dividend payment, which equates to an annual dividend of $2.21 per share. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65.0–70.0% of earnings.

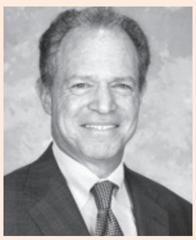
Range of WEC Energy Group Common Stock Prices and Dividends

	2017			2016		
Quarter	**High**	**Low**	**Dividend**	**High**	**Low**	**Dividend**
First	$ 61.53	$ 56.05	$ 0.520	$ 60.16	$ 50.44	$ 0.495
Second	$ 64.37	$ 59.61	0.520	$ 65.30	$ 55.46	0.495
Third	$ 67.20	$ 60.47	0.520	$ 66.10	$ 59.03	0.495
Fourth	$ 70.09	$ 62.84	0.520	$ 60.13	$ 53.66	0.495
Annual	$ 70.09	$ 56.05	$ 2.080	$ 66.10	$ 50.44	$ 1.980

BOARD OF DIRECTORS

John F. Bergstrom
Director since 1987.
Chairman and Chief Executive Officer of Bergstrom Corporation, which owns and operates numerous automobile sales and leasing companies.

Barbara L. Bowles
Director since 1998.
Retired Vice Chair of Profit Investment Management and Retired Chairman of The Kenwood Group, Inc., investment advisory firms. The Kenwood Group, Inc. was merged into Profit Investment Management in 2006.



William J. Brodsky
Director since 2015.
Chairman of Cedar Street Asset Management LLC, a Chicago-based portfolio management firm that specializes in investments in international equities.

Albert J. Budney, Jr.
Director since 2015.
Retired President and Director of Niagara Mohawk Holdings, Inc., a holding company that distributes electricity in areas of New York through its utility subsidiaries.

Patricia W. Chadwick
Director since 2006.
President of Ravengate Partners, LLC, which provides businesses and not-for-profit institutions with advice about the financial markets, business management, and global economics.

Curt S. Culver
Director since 2004.
Non-Executive Chairman of the Board of MGIC Investment Corporation and Mortgage Guaranty Insurance Corporation, a private mortgage insurance company.

Danny L. Cunningham
Director since 2018.
Retired Partner and Chief Risk Officer of Deloitte & Touche LLP, an industry-leading audit, consulting, tax, and advisory firm.

William M. Farrow III
Director since 2018.
Chairman and Chief Executive Officer of Winston and Wolfe LLC, a privately held technology development and advisory company.

Thomas J. Fischer
Director since 2005.
Principal of Fischer Financial Consulting LLC, which provides consulting on corporate financial, accounting, and governance matters.

Gale E. Klappa
Director since 2003.
Chairman of the Board and Chief Executive Officer of WEC Energy Group, Inc.

Henry W. Knueppel
Director since 2013.
Retired Chairman and Chief Executive Officer of Regal Beloit Corporation, a leading manufacturer of electric motors, mechanical and electrical motion controls, and power generation products.

Allen L. Leverett
Director since 2016.
President of WEC Energy Group, Inc.

Ulice Payne, Jr.
Director since 2003.
Managing Member of Addison-Clifton, LLC, which provides global trade compliance advisory services.

Mary Ellen Stanek
Director since 2012.
Managing Director and Director of Asset Management of Baird Financial Group; Chief Investment Officer, Baird Advisors; President, Baird Funds, Inc. Baird Financial Group provides wealth management, capital markets, private equity, and asset management services to clients worldwide.

OFFICERS

The names and positions as of December 31, 2017 of WEC Energy Group's officers are listed below.

Gale E. Klappa [(1)] [(2)] - Chairman of the Board and Chief Executive Officer.

Allen L. Leverett [(1)] [(2)] - President.

Robert M. Garvin [(1)] - Executive Vice President-External Affairs.

Margaret C. Kelsey [(1)] [(3)] - Executive Vice President.

J. Patrick Keyes [(1)] - Executive Vice President-Strategy.

Scott J. Lauber [(1)] - Executive Vice President and Chief Financial Officer.

Susan H. Martin [(1)] [(3)] - Executive Vice President, General Counsel and Corporate Secretary.

M. Beth Straka [(1)] - Senior Vice President-Corporate Communications and Investor Relations.

Darnell K. DeMasters - Vice President-Federal Government Affairs.

William J. Guc [(1)] - Vice President and Controller.

James A. Schubilske [(1)] - Vice President and Treasurer.

Keith H. Ecke - Assistant Corporate Secretary.

David L. Hughes - Assistant Treasurer.

[(1)] Executive Officer of WEC Energy Group as of December 31, 2017.

[(2)] On October 12, 2017, WEC Energy Group filed a Form 8-K to disclose that Mr. Leverett had suffered a stroke. The Board of Directors of WEC Energy Group appointed Mr. Klappa to act as Chief Executive Officer of WEC Energy Group until such time as Mr. Leverett is able to resume those responsibilities.

[(3)] In July 2017, WEC Energy Group announced Ms. Martin's intent to retire in early 2018. As part of that transition, effective January 1, 2018, Ms. Kelsey was appointed Executive Vice President, General Counsel, and Corporate Secretary of WEC Energy Group, and Ms. Martin was appointed Executive Vice President of WEC Energy Group.

The following individuals were also executive officers of WEC Energy Group as of December 31, 2017:

- J. Kevin Fletcher - President of WEC Energy Group's Wisconsin segment, which includes Wisconsin Electric Power Company, Wisconsin Gas LLC, and Wisconsin Public Service Corporation.
- Charles R. Matthews - President of Peoples Energy, LLC, and President and Chief Executive Officer of The Peoples Gas Light and Coke Company and North Shore Gas Company.
- Tom Metcalfe - Executive Vice President-Generation of Wisconsin Electric Power Company and Wisconsin Public Service Corporation.
- Joan M. Shafer - Executive Vice President-Human Resources and Organizational Effectiveness of WEC Energy Group's Wisconsin utility subsidiaries. Ms. Shafer announced that she will be retiring effective May 1, 2018.

Stockholder Information

Account Information

Visit **www.computershare.com/investor**.
WEC Energy Group's transfer agent, Computershare, provides our registered stockholders with secure account access. Stockholders can view share balances, market value, tax documents and account statements; review answers to frequently asked questions; perform many transactions; and sign up for eDelivery, the paperless communication program. eDelivery also provides electronic delivery of annual meeting materials.

- Write to:
  WEC Energy Group
  c/o Computershare
  P.O. Box 505000
  Louisville, KY 40202

- If sending overnight correspondence, mail to:
  WEC Energy Group
  c/o Computershare
  462 South 4th Street
  Louisville, KY 40202

- Call Computershare at 800-558-9663. Service representatives are available from 7 a.m. to 7 p.m. Central time on business days. An automated voice-response system also provides information 24 hours a day, seven days a week.

Securities analysts and institutional investors may contact our Investor Relations Line at **414-221-2592**. Stockholders who hold WEC Energy Group stock in brokerage accounts should contact their brokerage firm for account information.

Stock Purchase Plan

WEC Energy Group's Stock Plus Investment Plan provides a convenient way to purchase our common stock and reinvest dividends. To review the prospectus and enroll, go to **wecenergygroup.com** and select the Investors tab. You also may contact Computershare at **800-558-9663** to request an enrollment package. This is not an offer to sell, or a solicitation of an offer to buy, any securities. Any stock offering will be made only by prospectus.

Dividends

Dividends, as declared by the board of directors, typically are payable on the first day of March, June, September and December. Stockholders may have their dividends deposited directly into their bank accounts. Please contact Computershare to request an authorization form.

Internet Access Helps Reduce Costs

You may access **wecenergygroup.com** for the latest information about the company. The site provides access to financial, corporate governance and other information, including Securities and Exchange Commission reports.

Annual Certifications

WEC Energy Group has filed the required certifications of its Chief Executive Officer and Chief Financial Officer under the Sarbanes-Oxley Act regarding the quality of its public disclosures. These exhibits can be found in the company's Form 10-K for the year ended Dec. 31, 2017. The certification of WEC Energy Group's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards will be filed with the NYSE following the 2018 Annual Meeting of Stockholders. Last year, we filed this certification on May 26, 2017.

CR's
100 Best Corporate Citizens
2017

Corporate Responsibility

WEC Energy Group is committed to sustainable business practices — aligning our policies and practices with the needs of key stakeholders, and managing risk while accounting for the company's economic, environmental and social impacts.

www.wecenergygroup.com/csr

WEC Energy Group

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